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Long-Run Network Pricing for Security of Supply in Distribution Networks

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Long-Run Network Pricing for Security of Supply in Distribution Networks

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Contents

Abstract

Under the deregulated and privatized environment, network pricing is playing two crucial roles in electric power industry: 1) to recover network investment costs by operators, 2) to provide economic incentives to influence where and when network users will use and connect to the networks. It is desirable that network charging methodologies are able to truly reflect the degree of the use of systems by network users and price them accordingly. The aim is to influence the behaviors of prospective users especially distributed generators (DGs) so as to incentivize efficient utilization of existing networks thus minimize the investment cost for its future development.

Since 1980s, a vast number of pricing methodologies have been proposed. Most of them work at the transmission level to reflect the distance certain transactions have to travel from sources to sinkers and accordingly attribute the network cost. They are limited to how to attribute the existing network to existing customers, but do not look ahead of time to actively reduce the future network investment cost. In the UK, the distribution reinforcement model (DRM) has been the foundation for distribution charging since its introduction. It is based on year-ahead network investment from historical projection and allocates this to network users based on postage stamp, i.e. the same yardstick for the same voltage level. This approach is no longer able to effectively cope with increasing distributed generation and responsive demand. Hence, a revolutionary charging model for distribution networks pricing, long-run incremental cost pricing (LRIC), was proposed by University of Bath (UoB) in conjunction with the office of gas and electricity markets (Ofgem) in the UK and Western Power Distribution (WPD).

It is expected that network charging should be cost-reflective so as to price users in accordance with their actual use-of-system extent and thus, produce forward-looking signals to influence users' prospective behaviors to benefit network efficiency, security and reduce its costs. Network security, as a major driver for network investment, however, has not been well recognized in charging models.

Therefore, this work has carried out intensive research in this area based on the existing LRIC charging model utilized in extra-high voltage (EHV) distribution networks in the UK. As noted by Ofgem, it represents the best available model to incentive appropriate connection of distributed generation and demand responses. The target of this work is to improve the cost-reflectivity of this original LRIC model in two accounts: 1) reflecting the impact that customers place on network security; 2) reflecting the impact that network security placed on network investment. The major work can be summarized as

- Improve the computational efficiency of the existing LRIC model;
- Examine customers' impact on network components in contingencies and incorporate it into network charging;
- Devise a new model that can price customers according to their different security preference;
- Improve the existing LRIC model to make it able to capture the probabilistic characteristic of networks and nodal unreliability tolerance.

These concepts are firstly illustrated on simple two-busbar or three-bushar systems for simplicity and clarity. They are then demonstrated on practical distribution systems taken from the UK networks and compared with the original LRIC model in terms of cost-reflectivity, transparency and their potential impact on customer behaviors and on the network security and reliability. Test system demonstrations prove the effectiveness of the new philosophies and their advantages in better reflecting customers' impact on networks and their potential in influencing users' activities for enhancing network security and reducing the otherwise needed investment.

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List of Abbreviations

European Union	EU
Greenhouse Gases	GHG
Distributed Generator	DG
GB Security and Quality of Supply Standards	GB SQSS
Engineering Recommendation P2/6	ER P2/6
Distribution Network Operator	DNOs
Use-Of-System	UoS
Transmission Use-of-System	TUoS
Distribution Use-of-System	DUoS
Locational Marginal Pricing	LMP
Long-Run Incremental Cost	LRIC
Long-Run Marginal Cost	LRMC
University of Bath	UoB
Office of Gas and Electricity Markets	Ofgem
Western Power Distribution	WPD
Extra-High Voltage	EHV
Expected Unserved Energy	EUE
Department of Energy and Climate Change	DECC
Electricity Networks Strategy Group	ENSG
Short-Run Incremental Cost	SRIC
Short-Run Marginal Cost	SRMC
Investment Cost-related Pricing	ICRP
Direct Current	DC
DC Load Flow ICRP	DCLF ICRP
Distribution Reinforcement Model	DRM
Forward Cost Pricing	FCP
Scottish and Southern	SSE
Central Networks	CN
Scottish Power	SP

Électricité De France	EDF
High Voltage	HV
Low Voltage	LV
Load Growth Rate	LGR
Expected Energy Not Supplied	EENS
Mean Time To Repair	MTTR
Failure Rate	FR
Operation and maintenance	O&M
Rate of return	ROR

List of Symbols

Maximum allowed power flow of a component	C
Current loading level of a component	D
Flow change along a component	ΔP
Asset cost	$Asset$
Reinforcement horizon of a component	n
New reinforcement horizon of a component	n_{newr}
Discount rate	d
Load growth rate	r
Modern equivalent asset cost of the circuit	$Cost$
Present value of a component	PV
Change in present value of a component	ΔPV
Annuity factor	$AnnuityFactor$
Power flow along a component	P
Nodal power injection size	ΔPI
Nodal voltage altitude	V
Nodal voltage angle	θ
Nodal tariff at busbar	$Tariff$
Fixed adder in revenue reconciliation	$Adder$
Fixed adder in revenue reconciliation	$Multiplier$
Component rated capacity	RC
Component contingency factor	CF
Maximum contingency flow of a component	D_{cont}
Original reinforcement horizon of a component in contingencies	n_{cont}
Flow change of a component in contingency	ΔP_{cont}
Interruptible load part along a component	D_{inter}
Uninterruptible load part along a component	D_{unint}
Maximum uninterruptible flow of a component in contingencies	$D_{unint,cont}$
New horizon due to interruptible load in contingencies	$n_{cont,new}$
New horizon due to uninterruptable load in contingencies	$n_{cont,new}$

Uninterruptible flow due to uninterruptible connection	ΔP_{cont}
Mean time to repair a component	*MTTR*
Failure rate of a component	*FR*
Tolerable loss of load	*TLoL*
Allowed loss of load	*ALoL*

Chapter 1

Introduction

THIS chapter briefly describes the background, motivation, objectives, and contribution of this work. It also provides an overview of the thesis.

1.1 New Environment for Electric Power Systems

1.1.1 Deregulation and Privatization

Electric power is vital to human daily life and social development in that it provides energy for people not only to cook food, power machines, but also to light up darkness and warm coldness. Until early 1990s, all power industries around the world had been state-owned and centrally-controlled by government or authorized agencies, in which customers' prices were regulated as well. Under the circumstances, network utilities could also own generators and by making use of them, they can achieve their targets such as maximizing profits and reducing costs.

The characteristic of the traditional vertically integrated utility model was that a utility plans and builds its own generating plants, transmission, and distribution facilities in a manner that minimizes the overall cost of operating its electric system [1]. It was also a local monopoly, in the sense that in any areas one company or government agency sold electric power and services to all customers [2]. The traditional power industry had several characteristics [3]:

- Monopoly franchise: only the national or local electric utility was permitted to produce, transmit, distribute and sell commercial electric power within its service territory;

- Obligation to serve: the utility had to provide electricity for the needs of all consumers in its service area, not just those that were profitable;

- Regulatory oversight: the utility's business and operating practices had to conform to guidelines and rules set by government regulators;

- Regulated rates: the electric utility's rates were either set or regulated in accordance with government regulatory rules and guidelines;

- Guaranteed rate of return (the definition of rate of return is given in Appendix. B): the government guaranteed that regulated rates would provide the electric utility with a reasonable or fair profit margin on top of its cost;

- Least cost operation: the electric utility was required to operate in a manner that minimized overall revenue requirements.

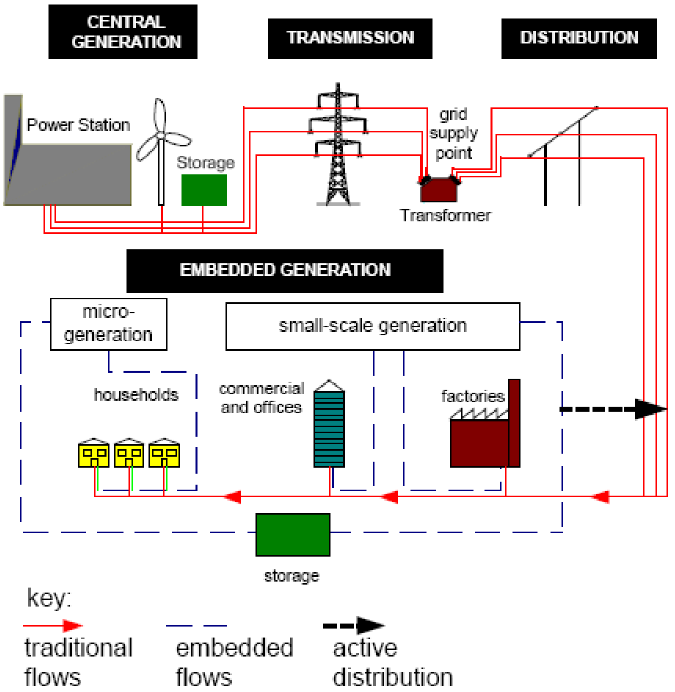

Figure 1-1 UK network scheme and its customers [4]

Although this naturally monopoly regime worked fine then, it impeded competition and efficiency promotion in the sector and failed to meet generation technology progress and other new social requirement for more open and efficient networks.

In order to enhance its efficiency and promote competition in it, privatization and deregulation was introduced into the England and Wales networks in early 1990s as well as some other networks worldwide. Since then, market forces have been playing a vital role in network operation and planning. Government's intervention in this new environment is reduced to the minimum extent so that generation and demand can to the maximum degree rely on market economic signals to make decisions.

In general, the open access refers to the regulatory constructions (e.g., rights, obligations, operational procedures, economic conditions) enable two or more parties to use a network, belonging totally or in part to another party or parties, for electric power transfer [5]. This reform makes it important to calculate the contributions of individual generators and loads to line flows and the real power transfers between individual generators and loads [6]. The tangible benefits are not only in lowering users' electricity prices but also in incentivizing other types of generation to play increasingly important roles in providing energy especially to load centers so as to defer potential network reinforcement.

On the other hand, however, uncertainties might emerge from generation and demand growth in addition to other aspects under this open market. Unfortunately, network utilities have no control as well as precise information concerning them. These uncertainties could impose tremendous challenges on network expansion and operation for operators; whereas they can rely on economic signals to minimize the uncertainties by sending economical signals to influence customers' behaviors.

1.1.2 Climate Change and Renewable Generation

Over the past decade, the problem of global climate change has stimulated all countries to limit and reduce their greenhouse gas emissions.

In 1997, most of the counties met in Kyoto to discuss and seek possible ways to fight the global warming problem, which led to the development of "Kyoto Protocol". Under the Protocol, 39 industrialized countries and the European Union(EU) commit themselves to a reduction of four greenhouse gases (GHG) (carbon dioxide, methane, nitrous oxide, sulphur hexafluoride) and two groups of gases (hydrofluorocarbons and perfluorocarbons) produced by them, and all member countries give general commitments [7].

In 2002, the EU ratified the "Kyoto protocol" as a shared effort with other countries to reduce global greenhouse gases emissions in order to mitigate climate change. The "a practical guide to a prosperous, low-carbon Europe" project is based on European leaders' commitment to a 80-95% reduction in CO_2 emissions by 2050. According to the 'roadmap 2050', 80% CO2 reduction overall implies 90-95% reduction in power, road transport and buildings. This could be achieved by maximum abatement within and across sectors. The most influential sector will be power and vehicle transportation. This level of decarbonization is dependent on achieving aggressive 2% year on year energy efficiency savings, without which this level of abatement is not possible in this model [8, 9].

The UK government has also committed to emission reduction targets at both EU and international levels.

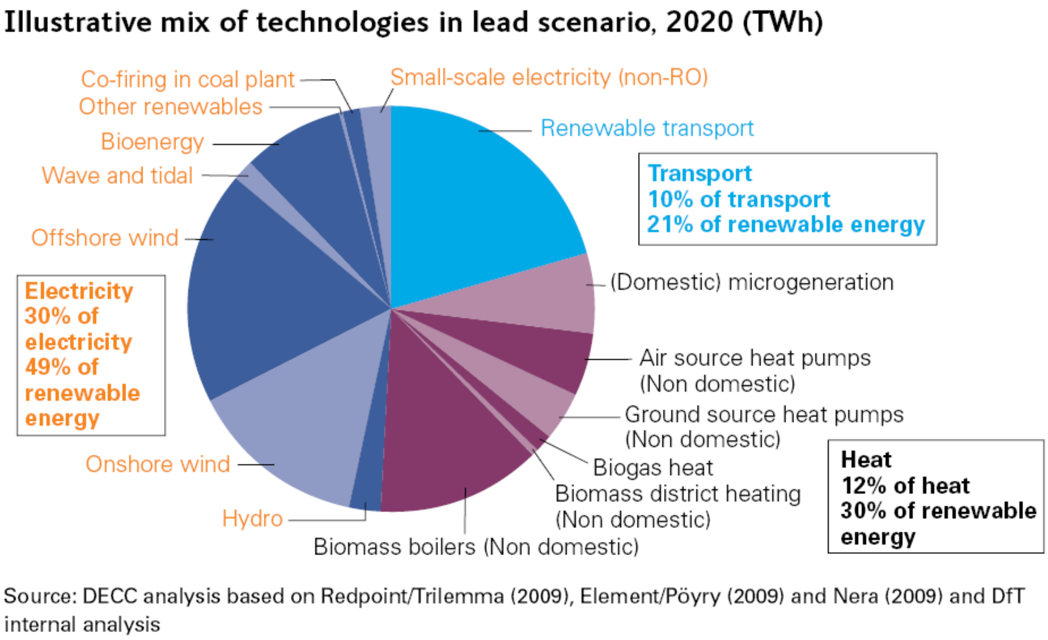

Figure 1-2 UK renewable target [10]

The government has promised to cut CO2 emission 18% in 2020 on 2008 levels and 80% by 2050. In order to meet this target, the government has to increase the amount of energy generated from renewable sources from the rate of 2% to 15% by 2020 and probably 100% by 2050 [11].

In 2009, the government published the white paper “The UK Low Carbon Transition Plan –National Strategy for Climate and Energy”, outlining a broad number of polices, targets and principles that will allow the UK to deliver its plan [12]. The lead scenarios in Renewable Energy Strategy suggest that by 2020: 1) more than 30% of electricity generated from renewables, up from the current level of 5.5%; 2) 12% of heat generated from renewables, up from the current very low level; and 3) 10% transport energy from renewables, up from the current level of 2.6% [10]. It also sets out the role that everyone can have in promoting renewable energy, from individuals to communities to businesses.

In order to assist the delivery of the target, a substantial number of distributed generators (DGs) especially those green-resource-powered ones have emerged. DGs are small-size generators connected to or near load centres to meet demand. They have lots of economic and technical merits for network operation and planning (the detailed aspects are discussed in section 2.1.1) and, most importantly, those renewable-powered DGs can dramatically reduce CO_2 emission. Another recent significant progress is the appearance of smart grid (the detailed discussion is in section 2.1.1), which can also help to deliver the target. Smart grid refers to the modernization of power systems by integrating new information technologies and providing more service choices in order to promote the interaction between generators, networks and consumers, and to accommodate different generation options. Its merits exist in many aspects, from reducing greenhouse gas emissions to cutting customers' bills and to improving network security.

Apart from these benefits, DGs and smart grid also bring great challenges for network planning, in terms of intermittence of renewable resources, the restructure of networks and the increasing participation of customers. Network planning philosophy thus should evolve accordingly to cope with these challenges.

1.1.3 Network Security of Supply

Although the new environment drives network utilities and other participants to seek maximum benefits, network users' security of supply cannot be degraded at all. The happened blackouts worldwide in the past led to a huge amount of monetary loss along with social chaos, which have alerted common public and network utilities the importance of security of supply. All regulated utilities have to follow certain security standards that are approved by market regulators. In the UK, the GB Security and Quality of Supply Standards (GB SQSS), which came out in 2004, sets out the minimum requirements for the planning and operation of GB transmission system [13]. For distribution network planning, the new Engineering Recommendation P2/6 (ER P2/6) outlines the standard of security of supply for distribution network operators (DNOs) to comply with [14].

Conceptually, network users would favor high security levels, as their supply is less likely to be interrupted and the overall resultant costs (electricity cost and the cost of loss of supply) could be lower. But, security is not free. In order to maintain an acceptable level of security, network utilities need to ensure enough investment in their networks, such as building new lines and transformers or upgrading existing components to provide sufficient availability of network capacity. This might comes at excessive investment cost, which sometimes could be even higher than the loss from network insecurity. Theoretically, an ideal network expansion philosophy is not to make unconstrained investment, but to find the right balance between investment cost and network insecurity cost. Although the balance is often hard to reach, network operators can rely on supplementary approaches to guide users' behaviors for the sake of security so as to avoid overinvestment.

1.2 Research Motivation

Under the new circumstances, the relationship between network utilities and users, i.e. generation, and demand, is commercial. The utilities provide networks to generation and demand to transfer their energy supply and demand, and in turn generation and demand pay for their use of the systems. The payment comes in the form of use-of-system (UoS) charge, which appears at both transmission and distribution levels, defined as transmission use-of-system (TUoS) charge and distribution use-of-system (DUoS) charge respectively. Presently, the two major types of network charging models utilized by utilities to recover their reinforcement and refurbishment costs are: long-run incremental cost (LRIC) pricing and long-run marginal cost (LRMC) pricing. Their embedded concept is the same and the only difference is in their implementation: LRIC is implemented in an incremental way by assessing users' impact on networks with and without them; whereas LRMC works in a marginal way, which first finds out the impact on networks from a unit generation or demand and it then enlarges the unit cost to users by multiplying it with their actual sizes.

The importance of long-run network charging has never been deemed as before since privatization and deregulation was introduced into power industry. It is desirable that network charges could discriminate between users who incur additional operating costs or network reinforcement and expansion, and those who reduce or delay the needed network upgrades. This feature requires that charging models are able to produce cost-reflective locational messages to reflect users' impact on network and to influence their prospective behaviors.

The LRIC pricing model proposed by the University of Bath (UoB) in conjunction with the Office of Gas and Electricity Markets (Ofgem) and Western Power Distribution (WPD) is the first charging model that directly links nodal injections and network investment. It makes use of the spare capacity of an existing network to reflect the costs of advancing or deferring future investment consequent upon the addition of generation or demand at each study node [15]. The produced locational and cost-reflective charges can influence potential network users. Based on the profound benefit analysis of applying this model to the UK distribution network, Ofgem has urged all DNOs to overhaul their present charging models. By now, the core of this charging model has been adopted by three major DNOs in their extra-high voltage (EHV) distribution networks in the UK [16].

The cost to maintain network security could take up a large proportion of investment, and hence network charging models should be able to reflect network security and allocate the related cost among customers. A great deal of transaction-based pricing methodologies (the detailed discussion is in section 2.5.1) for this purpose can be found at transmission level. But they can hardly be employed to distribution networks because they are transaction-based, unable to handle a large number of customers simultaneously and also because their calculation is based on the existing system status, generating no forward-looking signals to influence customers' behaviors. The LRIC model does respect network security of supply by introducing a contingency factor for components to reshape their maximum available capacity. But it fails in differentiating the importance of the components in contingencies to different users, which therefore needs to be improved.

1.3 Problem Statement

Although the LRIC model is quite advanced, it still has disadvantages concerning its efficiency and treatment of network security in charge evaluation. The following are four major issues.

1.3.1 Heavy Computational Burden

The impact of a nodal increment on network components in LRIC model can be divided into three interrelated parts: its impact on their flows, the impact of their flows on their reinforcement horizons, and the impact of the horizons on their present value of reinforcement costs (the definition of present value is given in Appendix. B). In order to assess the three components, the original LRIC model needs to run power flow analysis twice for each studied node. Such simulation approach is rather easy to implement but might cause heavy computational burden especially for large-scale systems [17, 18]. For a large-scale system with 2000 nodes, it takes the LRIC around 12 seconds to calculate LRIC charge for a single node and approximately 6 hours and 40minutes in total. This calculation burden is rather bothering if network operators need to run the LRIC several times to assess the impacts from nodal injections connecting to different locations. In addition, it is very difficult to rely on it to detect implementation errors, as the three components are combined together and determined through a single run of simulation. It is unable to directly provide additional informative messages for explaining issues such as why charge is high for a particular customer.

1.3.2 Improper Treatment of Network Contingencies

In order to reflect the costs from ensuring network security on network charges, contingency analysis is carried out along with the LRIC model to determine the maximum contingency flow along each component. A contingency factor therefore is defined for each component as its maximum contingency flow over its normal case flow and thereby utilized to reshape its maximum available capacity. In the LRIC model, the impact from a nodal injection on network components is only assessed in normal conditions with the range of components' maximum available capacity, but not in contingencies. This philosophy tries to capture the contingency case impact by resizing components' normal case available capacity. In reality, however, an injection could also bring forward or delay components' investment horizons in contingencies. This cannot be properly reflected simply with the strategy taken in the original model.

1.3.3 Unable to Respect Customers' Security Preference

Traditionally, network users at the same busbars are supplied with the same security levels and they have no other options to choose. Network expansion is also based on this principle. But, in this deregulated environment in the future, customers are granted with more freedom to choose different levels of security in line with their own need with the assistance of smart grid. Network utilities also have to react to more customer participation concerning network security to make their networks more flexible. Thus, charging models are expected to be able to differentiate users' preference for different security levels and price them accordingly. The existing charging models can hardly respect this, not to mention to actively influence users' activities. The LRIC model also fails in this aspect, but its capability of being able to produce locational economic signals makes it possible to be extended to respect users' different security requirement and price them.

1.3.4 Ignoring Probabilistic Characteristics of Power Systems

The present LRIC model uses deterministic criterion (such as, N-1, N-2 or even higher level security) to measure network security and then reflect it in charge assessment. It assumes that all components would definitely fail in charge evaluation period and all demand must be secured against certain level of contingencies. This philosophy, however, cannot recognize components' probabilistic characteristics but also the unreliability tolerance of demand set out by security standards, as both of them might have great influence on components' maximum available capacity and in turn the final charges. Network charging models thus should take both factors into account to actually recognize customers' impact.

1.4 Objectives and Contributions of This Study

In this thesis, the existing LRIC charging utilized at the EHV distribution networks in the UK is enhanced. Further improvement has been made to cater for the requirements from DNOs and users in this new environment concerning network security issue. The main objectives and contributions are outlined as:

- To improve the efficiency of the existing LRIC charging model and reduce its computational time through adopting alternative equivalent and easily implemented approaches. New proposed methods should not sacrifice accuracy for computational speed.

  In so doing, a novel analytical based LRMC pricing model for revenue reconciliation by inheriting the merits of the original LRIC model is proposed. It not only dramatically reduces computational time without sacrificing precision, but also provides further insights into factors that influence charges. (This part of work has been utilized by the DNOs in the UK.)

- To enhance the LRIC model by incorporating the impact of users on components in contingencies. Such impact should also be reflected in network investment cost and the final nodal charges.

  In so doing, the LRIC model is improved by taking users' impact on network components in both normal and contingency situations into account, which is translated into their reinforcement horizon variation. The comparison of the two new horizons is studied and the smaller one is chosen to derive final charges. The model can actually represent the change in network security and the related costs due to network users. (This part of work is only theoretical research.)

- To extend the LRIC model to price customers according to their security preference. The new model should be able to not only recognize their different security preference, but also respect their choices and price them accordingly. The produced charges are supposed to be cost-reflective to encourage users to go for different security levels.

  In so doing, a new charging concept for customers' security preference is introduced on the base of the original LRIC model. The new model works by categorizing demand at each busbar into interruptible part, which can be interrupted in contingencies, and uninterruptible part, which should be secured all times. Charges levied on them are derived by examining their impact on components in both normal and contingency situations. (This part of work is only theoretical research.)

- To extend the LRIC model by respecting both the probabilistic characteristics of network components and nodal unreliability tolerance mandated by network security standards. The new model should take both factors into account at the stages of components' reinforcement horizon evaluation and charge assessment. The resultant charges should be able to reflect the impact of the two factors.

In so doing, the LRIC model is extended by considering components' reliability characteristics as well as nodal unreliability tolerance. They are combined together and translated into yearly tolerable loss of load, which is then respected in component's maximum available capacity assessment. Unlike the original LRIC charging model working based on the outcome of the worst-case contingencies, this new model relies on the most serious risk contingencies, considering both their outcome and occurrence probability. (This part of work is only theoretical research.)

1.5 Thesis Outline

The rest of this thesis is organized as follows:

Chapter two provides a comprehensive literature review of challenges for network planning and charging in the new environment. It also introduces the widely utilized charging models, their basic concept, difference and limitations, with special attention paid to the models utilized in the UK. Further, it briefly goes through several charging models reported to recover investment cost with the consideration of network security or reliability at both transmission and distribution levels. This chapter also addresses the drivers behind network charging reform.

Chapter three proposes a novel LRMC pricing model based on analytical method for revenue reconciliation. It utilizes sensitivity analysis to work out the impact from a nodal injection on its supporting components' flow, on their reinforcement horizons, and finally on their present value of future reinforcement cost. It is tested and compared with the original LRIC model on an actual system and a two-busbar system in terms of charges and tariffs to demonstrate its effectiveness and applicability to actual systems.

Chapter four enhances the existing LRIC model by considering the impact from a nodal injection on components in contingencies. It firstly analyzes the impact from an injection on components in contingencies on a two-busbar network and a three-busbar meshed network to derive contingency case horizons for each component. Afterwards, the two new horizons from normal and contingency situations are compared and the smaller one is utilized to derive charges. In order to save computational effort, sensitivity analysis is used to work out the impact of the tiny injection on components' flow. This new model is finally compared with the original charging model by being applied to the practical system used in chapter three.

Chapter five proposes a new security-oriented charging model according to users' security preference. Demand at each busbar is firstly classified into interruptible and uninterruptible parts according to their different security preference. The approach then examines their impact on components' reinforcement horizons in both normal and contingency conditions and translates it into change of their present value of future reinforcement. This model is also tested and compared with the original security-oriented LRIC model on the actual test system.

Chapter six proposes a charging approach for network security considering components' stochastic characteristics as well as nodal unreliability tolerance. It investigates the impact from customers' unreliability tolerance and components' reliability levels on components' future reinforcement horizons on three typical networks: a single-circuit system, a parallel-circuit system and a meshed system. Based upon this, a reliability-based charging model is introduced. Charges are derived by examining the influence from components' mean time to repair and failure rate as well as nodal unreliability tolerance. Lastly, this model is demonstrated on the distribution system used in the foregoing chapters.

Chapter seven summarizes the key findings from the research and the major contributions of the work.

Chapter eight provides some potential research topics in network charging.

Chapter 2

Network Security and Pricing in New Environment

THIS chapter summarizes network planning security in the new environment. It also introduces the existing charging methods and discusses the interaction between security and charging.

2.1 Network Planning and Pricing

Since deregulation and privatization were introduced into the electric power industry, power generation, transmission and distribution have undergone dramatic change. In this deregulated context, transmission and distribution systems should not only be able to transport energy from sources to consumers with acceptable security and quality standards, but also to fulfill other tasks, such as accommodating increasing DGs and providing open access to market participants, etc. These requirements impose great challenges on network planning, especially at distribution level.

2.1.1 Challenges for Distribution Network Planning

The challenges for distribution network planning come from several aspects, the major three of which are from the uncertainties in demand and generation, growth in renewable-powered DGs due to CO_2 emission reduction, and the requirement for desirable security levels.

Uncertainties and Conflictive Objectives in Network Expansion

Traditionally, power systems were entirely owned and operated by government or authorized agency and they had the full access to the information concerning every aspect of the systems. In this new environment, however, networks are deregulated and privatized and their owners and operators would face numerous uncertainties in terms of [19]: 1) load forecast [20]; 2) availabilities of generators, transmission and distribution lines, and other network facilities: 3) energy at risk; 4) expected unserved energy (EUE) cost, etc.

These uncertainties significantly challenge the traditional reliability-driven least-cost network expansion philosophy. The reason is that it relies on the knowledge of potential pattern of demand and generation and expands networks with the minimum expense in line with security requirement. It is, however, unable to properly handle the emerging uncertainties. Another disadvantage impedes the use of the concept in this new environment is that it designs networks with one single target, least cost, which might violate the real practice. The new context requires that network planning to be able to cope with multi conflictive objectives simultaneously, such as [19, 21]: 1) facilitating competition among market participants; 2) providing non-discriminatory access to all generation resources for all customers including renewables; 3) minimizing investment risk; 4) enhancing network reliability, etc.

New planning methodologies thus have to be robust and flexible to recognize those uncertainties as well as to find an acceptable balance between those conflictive objectives. A potential expansion plan devised by this type of approach needs to be assessed in two dimensions: one is the traditional technical analysis to examine network reliability, security, feasibility and environmental impact, etc; and the other is to evaluate network economic impact on society [22].

Growth of DGs and Emergence of Smart Grid

Under the pressure to reduce CO_2 emission, the UK government is emphasizing the necessity of generating electricity from renewables. As a result of the stimulation effect of the government policy to encourage renewable generation, a great number of renewable-powered DGs have emerged. DGs have short a construction time, lower capital cost and quick payback periods. Their benefits exist in various aspects for network planning and operation, such as improving network reliability, deferring potential network development, and reducing power loss, etc. The general classification of the benefits of DGs are listed below [23, 24].

Major technical benefits include:

- Reduced line losses
- Voltage profile improvement
- Reduced emissions of pollutants
- Increased overall energy efficiency
- Enhanced system reliability and security
- Improved power quality

- Decongestioning transmission and distribution systems
- Increased security for critical loads

Major economic benefits are:

- Deferred investments for circuits upgrades or replacements
- Reduced Operations and Maintenance (O&M) costs of some DG technologies
- Enhanced productivity
- Reduced fuel costs due to increased overall efficiency
- Reduced reserve requirements and the associated costs
- Lower operating costs due to peak shaving

Apart from these benefits, they also bring great challenges to network planning. Their output is to a great extent dependent on the availability of resources, such as wind power, solar energy, which change with time, weather, locations, and other factors. This intermittent output makes it rather difficult to carry out network capacity expansion that exactly matches the needed capacity to accommodate them. A conservative expansion scheme could become a bottleneck to impede the increasing renewable generation, whereas an enthusiastic scheme would cause overinvestment. There should be equilibrium between investment cost and cost from insecurity to assist to devise cost-effective network expansion plans

In order to help the delivery of CO_2 reduction target and accommodation of increasing renewable-powered DGs, the smart grid concept had been introduced in many countries around the world. Its merits are broad, from improving grid reliability, promoting network operation efficiency to offering new products and services that give consumers greater flexibility in energy consumption.

According to the United States Department of Energy's “Modern Grid Initiative Report”, a modern smart grid must [26]:

- Be able to heal itself
- Motivate consumers to actively participate in operations of the grid
- Resist attack
- Provide higher quality power that will save money wasted from outages
- Accommodate all generation and storage options
- Enable electricity markets to flourish
- Run more efficiently
- Enable higher penetration of intermittent power generation sources

In the UK, an industry led policy advisory committee co-chaired by the Department of Energy and Climate Change (DECC) and Ofgem, The Electricity Networks Strategy Group (ENSG) published “A Smart Grid Vision” to examine what an UK smart grid might look like and the challenges it would help to address. It also published “A Smart Grid Route Map” for delivery of this version. According to it, in the near term up to 2020, the route map phases into two stages[25]: 1) present-2015, this stage mainly focuses on the proof of the concept, learning and development of desired technologies, whose major tasks including: network focused technologies, smart metering / smart grid integration, development of common standards, and security / privacy & testing / development, etc ; 2) 2015-2020, smart grid will be deployed in full scale. At this stage, the major works are to: apply the available smart grid solutions on electricity network where economic, fully integrate low carbon solutions, integrate commercial and market structures operating at scale (ongoing development and layering), etc. During the whole stage, the public should be engaged. The detailed information is given in Figure 2-1 [25]. In long term of 2025 onwards, it is the stage for delivering, when the power systems will have changed enormously by this time and the regulatory and commercial arrangements for the networks must support the ongoing progress towards a fully decarbonization future [27].

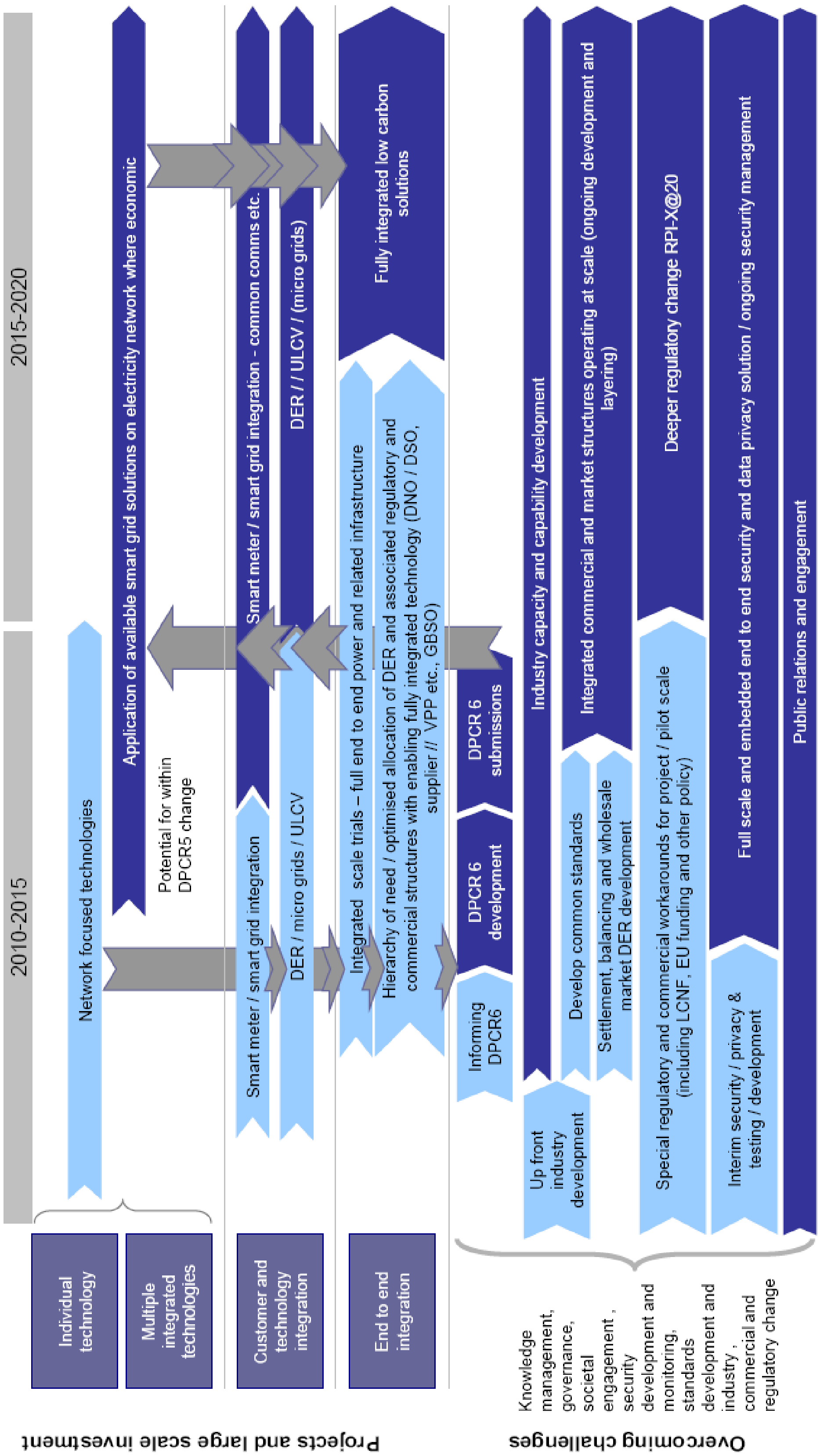

Figure 2-1 Integrated UK smart grid route map out to 2020 [25]

As smart grid continues supporting traditional loads, it can also facilitate the great use of fuel cells, renewables, micro turbines, and other DG technologies at local and regional levels and provides customers with more choices for supply. Apart from these benefits, it also brings problems, such as a need for network restructure, reverse power flow, and the increasing participation of customers to networks, which should be coped with by network expansion schemes.

Network Security and Investment

Since the foundation of the power industry, network security is vital to users. A higher level of security means that users' supply is less likely to be interrupted and hence the resultant cost from loss of supply is consequently low. On the contrary, if their security level is low, their supply is more likely to be interrupted, which could result in enormous monetary loss from loss of load [28, 29].

The importance of network security was recognized by network regulators a long time ago and they have also published some security standards to guide network planning. In the UK, the "Engineering Recommendation (ER) P2/5 – Security of Supply" coming into effect in 1978 is a distribution planning standard. Compliance with its provisions, it was an obligation imposed through distribution licenses upon DNOs since privatization [30]. It requires DNOs to provide enough assets and redundancy to meet minimum outage time. To date, the ER P2/5 has been replaced by the "Engineering Recommendation (ER) P2/6" which came into effect in 2006 to adapt to the new changes in power industry. Apart from outlining the security standard for different size customers, it also advises that DNOs can rely on the utilization of new type of DGs, especially those renewable-powered ones, as an alternative to network reinforcement as long as network security is satisfied.

Conceptually, higher security level is more preferable for users, but not for utilities. In order to maintain certain levels of security, network planners have to ensure enough investment in their networks, such as building new lines and transformers and upgrading existing components to provide sufficient spare capacity for catering for contingencies. Such scheme could come at excessive costs, which are eventually levied on network users [32-35].

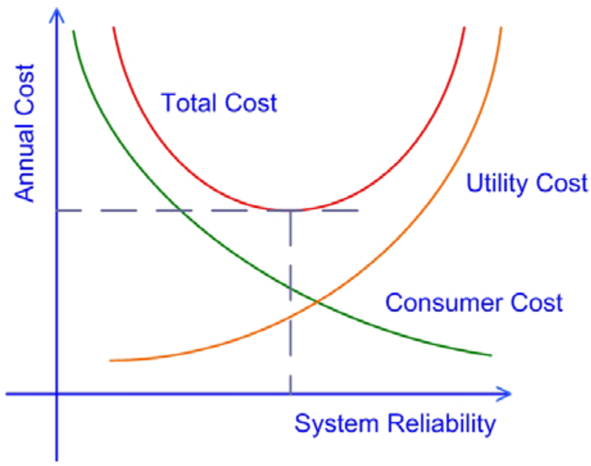

Figure 2-2 Trade-off between utility cost and consumer cost [31]

Figure 2-2 [31] demonstrates the basic concept of reliability-cost evaluation between utility cost and consumer cost. As shown, investment cost increases with the rise of reliability level and on the contrary, customers' interruption cost decreases as reliability increases. The total social cost is the sum of the two individual costs. Apparently, too higher and lower reliability levels are not cost-effective, but a minimum of the total cost can be achieved as demonstrated [36, 37]. It provides a useful concept for network planning. Although in reality such optimum is almost impossible to reach, suboptimal solutions might be attained.

2.1.2 The Roles of Network Charging

In this new environment, the only certainty that network utilities have is their existing networks and the spare capacity their networks have to accommodate potential generation and demand. Although utilities cannot force generation and demand to connect to specific locations, they can employ locational financial incentives to guide them to the locations that have enough network spare capacity so that least network upgrades are required. These incentives can be embodied in the form of network UoS charges [38] generated by pricing models.

The primary purpose of network pricing is to allocate the investment cost of network components among users who rely on them to withdraw or supply electrical energy. It is expected that pricing methodologies can effectively recover the costs, such as capital, operation and maintenance, etc, as depicted in Figure 2-3 [39].

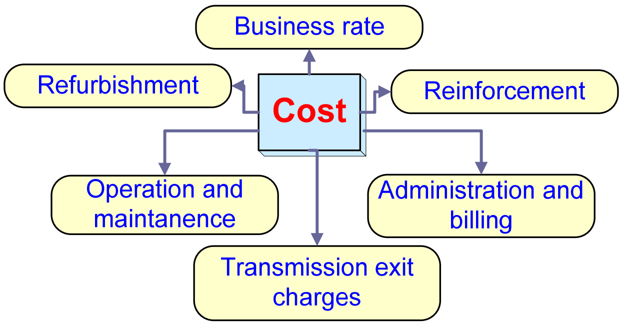

Figure 2-3 Identified key cost drivers

Network charge is not only important for utilities, but also for users especially those at distribution networks. As demonstrated in Figure 2-4 [39], for every 10 pence bill, customers in the UK need to pay approximately 2.1 p/kWh distribution charges and 0.3 p/kWh transmission charge, which take up about 21% and 3% of the total bill.

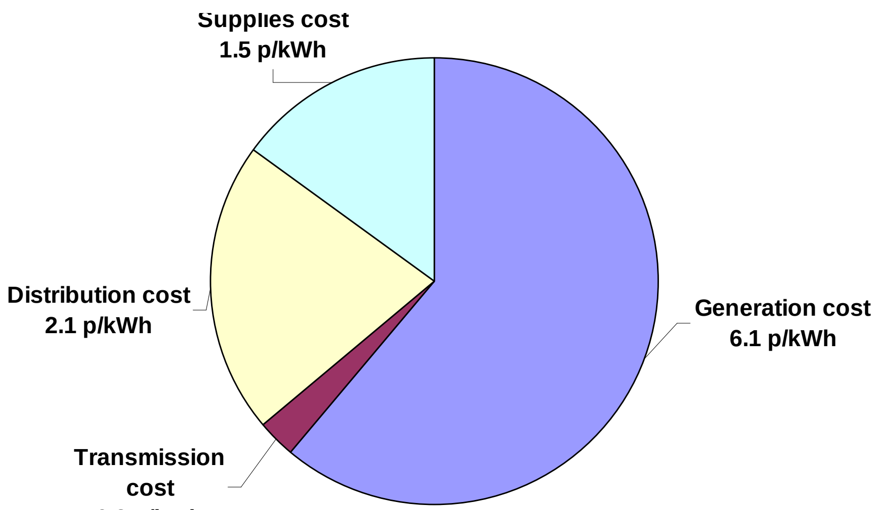

Figure 2-4 Cost components for every 10 pence electricity bill in the UK

Charges are set by network operators based on their assessment of system costs and fed into the charging models they adopt to determine the costs to accommodate the additional demand or generation at each level of systems. An appropriate cost recovery is then split among customers or customer groups. So, the output of charging models is the cost-reflective charge for each customer or group of customers. The revenue recovered from the charges may not exactly match with the allowed revenue (the definition of allowed revenue is given in Appendix. B). Therefore, these charges are then scaled up or down with fixed adder or fixed multiplier or other methods to allow operators to recover their cost plus a certain level of return. The allowed revenue needs to consider forecast capital and operational spending, growth in customer numbers and distributed units.

It is desirable that network charging models should not only be able to recover the investment in networks, but also provide forward-looking and economic guidance to the existing and prospective users to influence their activities in sitting and sizing so as to encourage efficient utilization of the existing networks.

2.2 Network Charging Methodologies

Over the past decade, a large number of charging methodologies have been proposed worldwide, most of which are utilized on transmission systems. According to the embedded concept behind them, they can be generally categorized into two categories: embedded pricing paradigm and incremental/marginal pricing paradigm.

2.2.1 Embedded Cost Pricing

Embedded cost pricing approaches include: 1) postage stamp methodology [40]; 2) contract path methodology [41]; 3) distance based MW-mile methodology [42]; and 4) power flow based MW-mile methodology [43]. These types of approach sum up all existing transmission system cost and the new cost from system operation and expansion for accommodating new comers into a single value. The cost is then divided among all users, including both old and new users, according to their extent of use of system [44]. Figure 2-5 demonstrates the base concept behind the models.

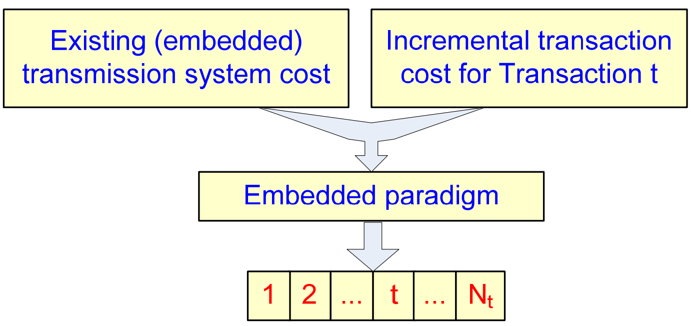

Figure 2-5 Schematic concept of embedded charging paradigm

Under this paradigm, network users need to pay the revenue recovered for all existing facilities plus the new facilities added during their contract period. The shortcomings of these embedded approaches are prominent: 1) postage stamp might suffer from the cases that energy is transmitted across several networks as it would accumulate high wheeling costs; 2) contract path method is unable to reflect the actual flows among the firm transmission service users; 3) distance-based MW-mile methodology can only reflect the distance that energy needs to travel, but fails in recognizing the utilization levels of components.; 4) power flow based MW-mile methodology only works on the existing system status, but is unable to recognize the demand and generation growth. These usage-based approaches are fairly easy to implement, but not economically efficient. They are unable to differentiate customers who incur additional operating costs or network reinforcement and expansion and those who reduce them need. Consequently, they can hardly reflect network resource scarcity.

2.2.2 Incremental and Marginal Cost Pricing

In order to overcome the disadvantages of embedded charging models, incremental/marginal cost pricing models are thereby proposed. This sort of methodologies only consider the new transmission costs incurred by new customers and then allocate the costs among them, with the existing costs still being the responsibility of existing customers. Figure 2-6 shows their schematic concept [44].

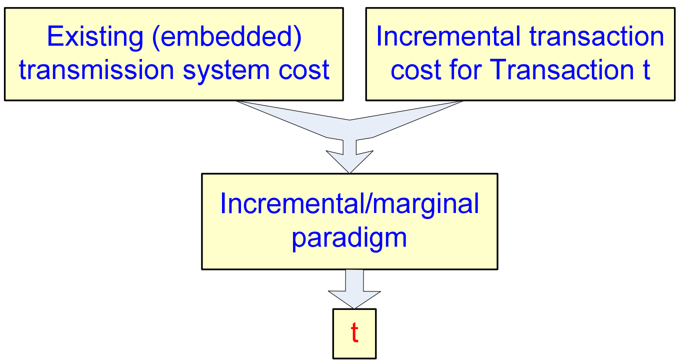

Figure 2-6 Schematic concept of incremental/marginal paradigm

There are two major factors associated with this kind of approach: 1) the span of time period, short-run or long-run and 2) the way the new transactions evaluated, incrementally or marginally. By taking different combinations of the two factors, the existing incremental/marginal cost pricing approaches fall into the following four categories: short-run incremental cost pricing (SRIC) [45], long-run incremental cost pricing (LRIC) [41], short-run marginal cost pricing (SRMC) [46], and long-run marginal cost pricing (LRMC) [47, 48].

The major difference between incremental and marginal pricing is in how they evaluate the cost due to additional transactions. Incremental approaches are carried out by comparing the cost with and without transactions. Marginal approaches, on the other hand, evaluate the cost needed to accommodate a unit additional transaction and then multiply the unit cost with the actual size of additional transaction. LRIC methodologies are fairly easy to implement but take longer computational time for large-scale systems, as two runs of simulation are needed to work out a transaction's impact. By contrast, marginal methods use analytical equations to evaluate the impact caused by a transaction on network development costs [49]. These equations usually are the functions depicting how network transactions would affect networks and eventually network investment costs [50, 51].

This type of approach is computationally efficient but based on the assumption that the relationship resulted from small injections can be extrapolated to large injections. Inaccuracies might be caused, as the relationship between nodal injections and network development costs is not linear.

The difference between short-run and long-run pricing approaches is that they focus on different part of cost incurred by an additional transaction. Short-run approaches evaluate the additional operating cost associated with a new transmission transaction and assign it to that transaction. By contrast, Long-run methods entail all evaluated long-run cost including maintenance and reinforcement cost necessary to accommodate a transaction and allocate the cost to that transaction.

2.2.3 International Experience of Network Charging

It should be noted that in practice, transmission and distribution network pricing has become an important issue since the deregulation and privatization of the sector in many countries. In Brazil, the Investment Cost-related Pricing (ICRP), which is going to be discussed in the following part (section 2.2.4), is utilized to calculate marginal costs for network users. Based on the historical data collected by network operators, the relation between load growth in one area and the increment of investments made in the past is investigated. The relation can be obtained and used to reflect the investments in the following years [52, 53].

The Locational Marginal Pricing (LMP), mainly utilized in the United States, is a market-pricing approach used to manage the efficient use of the transmission system when congestion occurs on the bulk power grid. In electricity, LMP recognizes that marginal prices may vary at different times and locations based on transmission congestion. LMP is quite efficient approach to achieve short- and long-term efficiency in wholesale electricity markets [54]. With LMP price, market participants will know the price of hundreds of locations on the system [55]. LMP can; 1) increase transparency of the true costs of serving load by location; 2) provide a consistent methodology to price transmission and energy across market time frames; 3) provide price signals for developing new generation and transmission resources in the best locations [56]. But, the LMP methodology has only been the dominant approach in power markets to calculate electricity prices and to manage transmission congestion, but it does not recover the investment in networks [57].

Table 2-1 Latin American Pricing Schemes [61]

Country	Argentina	Bolivia	Chile	Colombia	Perú
Generation-transmission pricing	Nodal pricing, based on bids	Nodal pricing, based on costs	Nodal pricing, based on costs	Single bus market price, based on bids	Nodal pricing, based on costs
Open access regulation	Fully regulated	Fully regulated	Negotiation process between parties is regulated	Fully regulated	Fully regulated
System to be paid	Determined by the regulator	Economically adapted system determined by the regulator	Negotiated by parties	Economic minimum system determined by the regulator	Economically adapted system determined by the regulator
Value to be paid	Replacement value, sunk values for existing installations at privatisation.	Replacement value	Replacement value	Replacement value	Replacement value
Paid by	Generators	Generators and consumers	Generators	Generators (50%) and consumers (50%)	Generators, transferred in tariff to consumers

In Norway, the tariffs in the central grid consist of four elements: two dependent on the short-run utilization of the grid and the other two are fixed on an annual basis. The tariff element covering losses is based on spot market prices of electricity and an approximation to the marginal loss caused by injection and consumption in a region for three typical load situations. This element covers approximately 25% of the total costs [58]. In Spain, its network pricing provides short-run signals by pricing losses and congestions. In the case that grid is less available than a determined reference level, the grid owner is penalized [59]. In New Zealand, electricity spot prices are equal to nodal marginal costs, and system expansions are justified if the difference in prices with and without a scheme equals the cost of the scheme [60]. For reference, the Table 2-1 summarizes the network pricing in Latin America [61].

2.2.4 Charging Models in the UK before 2007

In the UK, network charging models have also been utilized at both transmission and distribution levels after the reform in its power industry. Originally, ICRP is utilized at transmission network, which is then improved to a new DC load flow based ICRP (DCLF ICRP) [62] version by National Grid, UK, and Distribution Reinforcement Model (DRM) [16] is employed at distribution system.

Investment Cost-related Pricing

The ICRP model consists of two parts. The first one is the varying locational element from the DCLF ICRP transport model to reflect the cost from capital investment, maintenance and operation and the second part is the non-locational varying element related to the provision of residual revenue recovery [62]. In the basic ICRP model, power is assumed to flow to users along the shortest path whereas in the new model it is calculated with DC load flow analysis. Thereafter, the model assesses the marginal reinforcement cost required as the consequence of an increment in generation or demand at each studied busbar [63].

This model enables the differentiation in nodal cost to be determined and facilitates sensitivity analysis concerning alternative development of generation and demand to be taken. Although it seems applicable to EHV distribution networks, it could provide perverse signals for the locations of generation and demand under certain circumstances when applied to reference networks. The perverse signals in it encourage load to sites at the nodes that have the least distance from the associated GSP without reference to the utilization of the associated assets, causing these loads to require the most investment for the connection [64].

It may also sometimes produce unstable charges that "flip flop" between debit and credit for generation and demand for the locations that are relatively distant from grid supply point. Hence, it is not suitable to be used at distribution networks [16].

Distribution Reinforcement Model

DRM was proposed by Electricity Council in the UK in 1982 as an approach for cost allocation for DNOs. Since then, DRM has been the foundation for distribution tariff setting in England and Wales. Over the time, it has been revised by DNOs to facilitate the changes in policy [16].

This model measures the cost of connecting an additional 500MW capacity at the time of peak demand at each voltage levels. This 500MW injection has no particular technical significance (i.e. this 500MW is not the actually predicted load growth in each DNO's network) but to be large enough to have great impact on all voltage levels. It then averages the cost across users at each voltage level [65]. Generally, DRM has the following three step procedures [16]:

- Cost evaluation: cost of accommodating a 500MW injection at system peak.
- Cost allocation: yardsticks (the definition of yardstick is given in Appendix. B) at different voltage levels based on their use of upstream assets. Customers at the same voltage levels are considered to use the same level of upstream assets.
- Revenue reconciliation: any shortfalls between the recovered revenue and the allowed revenue are proportionally allocated among all network users through charge control techniques.

DRM is a simple postage stamp cost allocation approach, examining a nodal increment's impact by indentifying the distance the increment has to travel along its supporting components. It is rather transparent and very simple to implement, but the produced charges are neither locational nor cost-reflective.

2.3 Rationales for Change in Long-run Charging

Until early 1980s, almost every utility worldwide had integrated generation, transmission and distribution systems together with one price for consumers. The actual price must depend on the average cost to the utility of producing and delivering this energy, so differential prices for large, medium and small customers was the norm [66].

2.3.1 Reforms in Distribution Networks

Since the structure of electricity distribution charges was set by Electricity Council in the UK, it has not changed significantly, but UK's distribution network especially EHV network have undergone dramatic change.

One change is due to the pressure from climate change. Facing this issue, network utilities are also required to take the lead and responsibility to fight against it. Usually, the output of these renewable-powered generators changes greatly with the availability of the resources, such as wind and solar power, which in turn varies with time and weather. The intermittency of their output make it rather difficult for network planners to design their networks right to deliver the output, as they need to ensure sufficient network capacity to accommodate the energy as well as ensure security without too radical investment. Further, these renewable generators mainly locate in rural areas or far from load center, and thus enough circuits need to be built to transmit the increasing sustainable energy. DNOs in the UK have projected that significant capacity investment would be needed to accommodate the increase, costing about £5billion-£6billion for 2010-2015 [39]. On the other hand, the need to maximize benefits with minimum input urges DNOs to operate their networks quite closely to their limits. But, demand and generation still grows rapidly and their growth patterns are out of DNOs' control and they should be secured against certain network contingencies.

Structurally, to meet these challenges, distribution networks have changed from the traditional passive format to an actively dynamic format to accommodate the increasing demand. Further, as power generation becomes increasingly distributed and even more power is generated from renewable resources due to the pressure of

CO_2 reducing, distribution systems will need to facilitate more fluctuations in power quality, two-way power flow, and also be more responsive to changes in consumer demand. It could also include the connection of smart grid in homes, such as washing machines, refrigerators and freezers, with the possibility that they can be managed by local DNOs to provide active and reactive load control in the local network, taking smart metering to a new level of sophistication [67].

2.3.2 Disadvantages of the Existing Long-run Charging

The forgoing mentioned charging models, however, are no longer able to cope with the reforms recently appearing in distribution networks. It is against this background that Ofgem commissioned a study to investigate the benefits coming from moving to an alternative more economic charging model in terms of the cost in long-term network development [64].

One disadvantage with most of the existing approaches is that they require a least-cost future network planning in order to determine the cost of future network expansion with potential generation and demand growth pattern. It is impractical for LRIC pricing approaches to evaluate the cost associated with generation and demand injections at every studied node, as most of them calculate incremental cost for catering for the injections under a projected demand and generation pattern. Under the deregulated environment, the knowledge of future generation and demand is far from certain and not under the control of network utilities [15].

Another disadvantage is that these LRIC pricing models can only passively react to a set of projected patterns of future generation and demand, unable to actively influence the patterns with economic signals [15]. This incapability would bring great difficulties for utilities when they are planning networks with increasing customer participation and other responsive demand that are willing to react to the economical signals.

DRM is also no longer fit for the purpose anymore, as it fails to recognize the significant benefits potentially brought by DGs. The averaged charge for each voltage level tends to discourage the demand side management as well. Therefore, it needs to be improved somehow or other new distribution network charging models should be proposed in order to facilitate the changes.

2.3.3 Desirable Features of New Distribution Charging Models

In order to assist in tackling these new challenges, pricing objectives in this new environment should conform to the following guidelines [66]:

- Prices should be based on economic efficiency, costing resources in terms of fuel, conversion costs, and effects on the environment, not just in purely monetary terms;
- Prices should be firmly set in accordance with cost;
- Prices should ensure commercial viability;
- Equity between different classes of consumers should be maintained;
- Tariffs should be as simple as possible and transparent to all customers.

Thus, in order to deliver these objectives, network charging models utilized at distribution networks should contain the following features as required by Ofgem [66]:

- Cost reflectivity: charges should be levied on users in line with network cost drivers and able to reflect their use-of-system;
- Simplicity: charging methodologies should be as simple as possible to evaluate;
- Transparency: charging methodologies should be transparent to all participants, including network operators and users, and probably other interested parties;
- Predictability: charges should be based on long-run cost on a forward-looking basis to account for future potential reinforcement and be easily predicted;
- Facilitation of competition: charges should serve the purpose to influence prospective users' investment behaviors.

It is clear that in practice both trade-offs and complementarities exist between these different high-level charging principles. The principles of predictability, simplicity, transparency and the promotion of competition are strong complements in this respect, but will often be at odds with the objectives of cost reflectivity [66].

2.4 New Progress in Distribution Charging in the UK

In the UK, two new charging models, Forward Cost Pricing (FCP) methodology and Long-run Incremental Cost Pricing (LRIC) methodology have emerged and replaced DRM for EHV distribution network pricing.

2.4.1 Forward Cost Pricing Methodology

FCP methodology was initially developed by Scottish and Southern (SSE), Central Networks (CN), and Scottish Power (SP) for pricing users connected to EHV distribution networks [68, 69]. It treats generation and demand separately while evaluating their impact.

FCP demand price is calculated by assessing network reinforcement cost to support a maximum of 15% demand increment for each network group over the next 10 years rather than assets' lifetime [39]. The actual demand growth is from the forecast in each network group. Potential reinforcement cost is calculated and averaged at each voltage level within the same network group such that the total revenue recovered equals to the forecasted reinforcement cost plus a certain level of investment return.

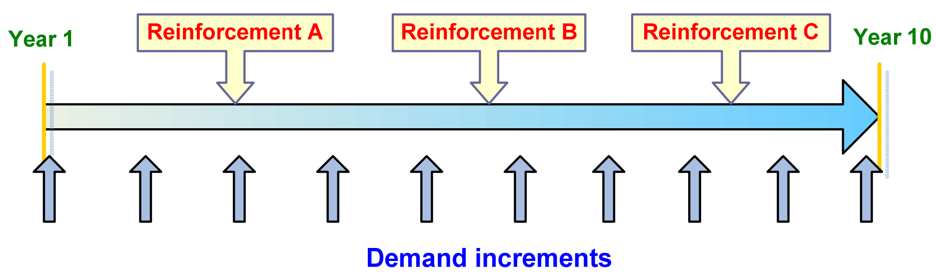

Figure 2-7 FCP charging for demand

FCP generation price consists of two parts: reinforcement cost and generation benefit. Reinforcement cost is evaluated by aggregating the cost of the total present value of the reinforcement project required to accommodate potential generators over 10 years.

The size of the test generator for each voltage level is 85th percentile of the existing generation size at that level [70]. Generation benefit comes because generators can reduce the needed reinforcement caused by demand increase. The benefit on a distribution network at each voltage level is set equal to the corresponding demand costs, scaled down by a factor that reflects the reliability of the generation technology suggested in ER P2/6 [68, 70]. Total FCP generation charge is generation cost minus generation benefit.

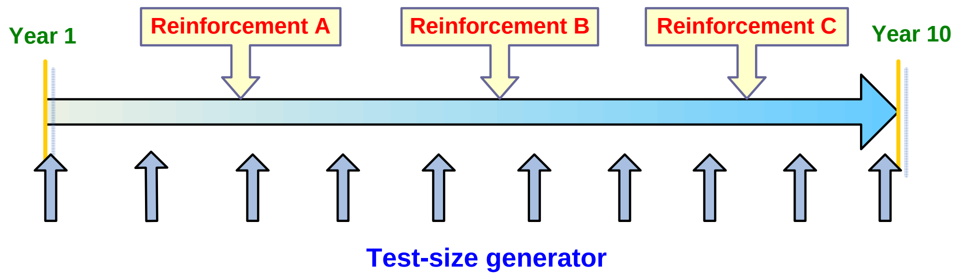

Figure 2-8 FCP charging for generation

Although FCP demand price is based on LRIC charging model, the locational signals are still weak as the nodal prices in the same network groups are the same. As for generation price, it is quite sensitive to the size of test generator and the forecasted new generation, so the resultant charges can vary significantly if different sizes of test generators are employed. Additionally, FCP is unable to recognize the interaction between demand and generation as it treats them separately in network planning.

2.4.2 Long-run Incremental Cost Pricing

This LRIC model was originally proposed by UoB in conjunction with Ofgem and WPD [15]. Unlike FCP, LRIC considers the impact of generation and demand together. It assumes that for components in networks affected by a nodal injection, either demand or generation, there will be a cost associated for the injection if a component's reinforcement horizon is accelerated or a credit if it is deferred. It works by examining the change in components' future reinforcement horizons affected by nodal injections and translating the change into the variation of the components' present value of future reinforcement. In it, components' investment horizons are decided by their present loading conditions, the predicted load growth rate and their available spare capacity. The final charge for a busbar is the summation of the price from all its supporting components calculated under a given discount rate.

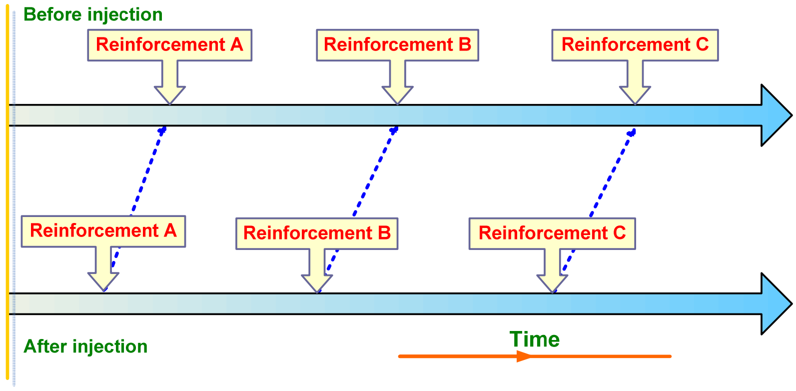

Figure 2-9 Principle of long-run incremental cost pricing

Generally, the LRIC model has the following three major implementation steps.

Step 1: Present Value of Future Investment

If a circuit l has a maximum allowed power flow of C_l supporting a flow of P_l, the number of years takes P_l to grow to C_l under a given load growth rate, r, can be determined with

$$C_l = P_l \cdot (1+r)^{n_l} \tag{2-1}$$

Rearranging (2-1) and taking the logarithm of it gives

$$n_l = \frac{\log C_l - \log P_l}{\log(1+r)} \tag{2-2}$$

Assume that investment will occur in year n_l when the circuit utilization reaches C_l. Under a chosen discount rate of d, the circuit's present value of future investment is

$$PV_l = \frac{Cost_l}{(1+d)^{n_l}} \tag{2-3}$$

Where, $Cost_l$ is the modern equivalent asset cost of the circuit.

Step 2: Cost Associated with Power Increment

If power flow change along circuit l is ΔP_l as a result of a nodal injection, its future reinforcement horizon will change from year n_l to year $n_{lnew,}$ decided by

$$C_l = \left(P_l + \Delta P_l\right)\cdot\left(1+r\right)^{n_{\ln ew}} \tag{2-4}$$

Equation (2-4) presents the new investment horizon n_{lnew}

$$n_{\ln ew} = \frac{\log C_l - \log\left(P_l + \Delta P_l\right)}{\log\left(1+r\right)} \tag{2-5}$$

Consequently, the new present value of future reinforcement becomes to,

$$PV_{\ln ew} = \frac{Cost_l}{\left(1+d\right)^{n_{\ln ew}}} \tag{2-6}$$

The change in the circuits' present value as a result of the injection is given by

$$g(r) = \Delta PV_l = Cost_l \cdot \left(\frac{1}{\left(1+d\right)^{n_{\ln ew}}} - \frac{1}{\left(1+d\right)^{n_l}}\right) \tag{2-7}$$

The incremental cost for the circuit is the annuitized change in its present value of future investment over its life span, given as

$$\Delta IC_l = \Delta PV_l \cdot AnnuityFactor \tag{2-8}$$

Where, ΔIC_l is the increment cost of circuit l due to the nodal injection. The definition of annuity factor can be found in Appendix. B.

Step 3: Long-run Incremental Cost

The nodal LRIC charge for a busbar is the summation of the all incremental costs from its supporting circuits, given by

$$LRIC_l = \frac{\sum_l \Delta IC_l}{\Delta PI_l} \tag{2-9}$$

Where, ΔPI_i is the size of power injection at the bus.

This LRIC model has the attribute of producing charges that are:

- Forward-looking;
- Able to reflect the extent of use of networks by a connectee;
- Able to reflect the degree of components' utilization;
- Respecting the discrete sizing of network components and their inherent indivisibility.

The Figure 2-10 demonstrates the implementation steps of the LRIC model

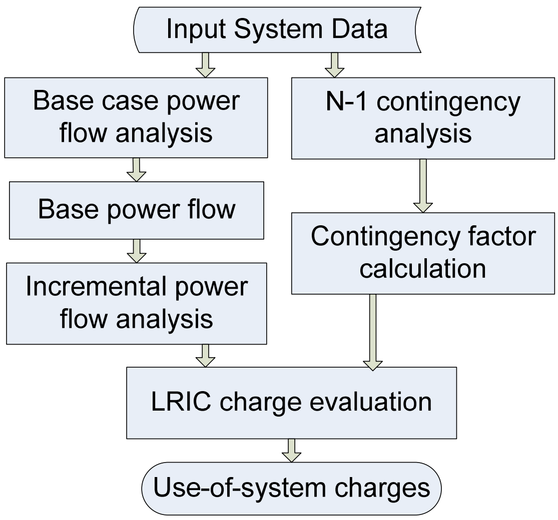

Figure 2-10 The implementation of the LRIC model

Its drawback is that so far it only works for network thermal constraints, and in some extreme cases with extreme small load growth rates and high loading levels, it would produce excessively high prices.

2.4.3 Present Charging Framework in the UK

Currently, Ofgem allows DNOs to use either LRIC or FCP in their EHV distribution networks to recover investment, but they need to submit their final selection to Ofgem for approval by 2011. By now, the core of the LRIC charging model has been adopted by three major distributors in the UK, WPD, Électricité de France (EDF) and CE Electric whereas other DNOs are applying FCP instead.

ICRP is still utilized on UK transmission system by National Grid and DRM is employed by DNOs on their High Voltage (HV) and Low Voltage (LV) distribution systems. Figure 2-11 shows the charging models utilized in the UK networks presently [39].

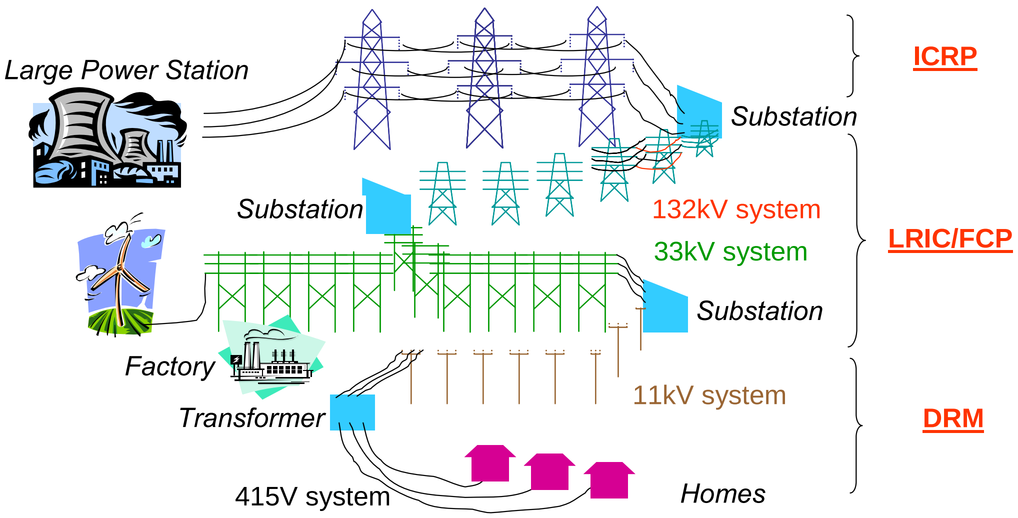

Figure 2-11 Charging methodologies in the UK after 2007

2.5 Network Charging for Security

As discussed in the foregoing sections, network investment to ensure security takes a very large portion of the total cost and should also be allocated reasonably among users. Thus, network charging methodologies are also expected to fulfill this task. They need to reflect users' different levels of security of supply and allocate the related cost among them [71, 72]. Theoretically, users with higher security levels should pay more for their priority whereas others with lower levels are responsible for less payment.

By now, many charging methodologies for security or reliability at transmission level have been published over the past decades, but few approaches have investigated the problems at distribution level.

2.5.1 Pricing for Security and Reliability at Transmission Level

Usually, this type of charging methodology divides the total cost associated with transmission service into two general categories:

- Transmission-use charge evaluated based on the extent of use of transmission networks by users in normal conditions;

- Transmission security or reliability margin benefit which is calculated in contingencies.

Here, the most important issue is to determine a reasonable ratio between capacity use charge and reliability/security benefit charge. According to the different indices they use to examine customers' security, the present pricing approaches for network security are categorized into the following two groups: pricing bases on network security and pricing based on network reliability.

Pricing based on Network Security

This category of approaches examines security benefits for transactions under the most serious contingencies, ignoring the occurring probabilities of these contingencies. Although some of them do consider occurring probability of contingencies, they are theoretically not actual reliability-oriented pricing since they do not consider the change in reliability levels of the whole systems due to the transactions.

In paper [73], the authors presents a reliability-based charging model, in which the ratio between capacity-use and reliability benefit components split is 80%-20%. Although it seems reasonable as demonstrated in the example, it could be a challenging task for transmission owners to choose the suitable ratios. In paper [74], the ratio between allocation of transmission line capacity-use and allocation of reliability benefits is calculated based on a devised reliability index. But the example shows that only a relatively small portion of reliability embedded cost is allocated to reliability benefits. Its weak signals can not greatly reflect users' different reliability benefits and influence their prospective behaviors.

Paper [75] proposes a new approach, in which the share of capacity use cost is in proportion to the sum of the absolute value of flows caused by transactions in normal states. Components' reliability margin for transactions is calculated through introducing a probabilistic index that is evaluated under N-1 contingencies. In this approach, counter flow can be a big problem, as it leads to the net circuit flow caused by the flows due to all transactions not being equal to the sum of absolute values. Further, it is highly dependent on the number of transactions, which in reality is very hard to predict.

The ICRP model does not factor network security. As implemented by NGC, it relies on post-processing through a full-contingency analysis to give an average security factor of 1.8 for components, which is utilized to reshape components' maximum available capacity [76]. The security factor is derived based on an average from a number of studies conducted by NGC to account for future network developments and reviewed for each price control period and fixed for the duration [63].

The selection of contingencies is based on an average from a number of studies conducted by National Grid to account for future network development. The security factor is reviewed for each price control period and fixed for the duration [63]. This uniform security factor, however, could be misleading, as it is unable to differentiate the importance of the same components to different users.

Pricing based on Network Reliability

Some other approaches price users by simulating the change in reliability margin with and without network users and then allocate the related costs from the decrease in reliability or the investment cost to ensure the same reliability levels among the users.

In paper [77], the regulated fixed charge is calculated with traditional transmission price. The reliability cost charge is evaluated by converting reliability indices, such as expected unserved energy, to a cost assessed with and without the wheeling transactions. The difference between the two costs is system reliability effect. Users are responsible for the total transmission price and transmission grid owners receive the regulated fixed charges. The reliability cost charge is held by regulatory agency to be granted to users who invest in transmission systems and cause the reliability levels to be improved. The major incentives in this approach are to encourage network utilities to expand their networks, but the benefits or incentives to network users are not apparent especially to demand users.

Papers [78, 79] present a method to incorporate reliability component in transmission service pricing with the consideration of load growth. In this approach, all customers are included to account for their effect on system reliability levels and share the responsibility of system reliability. It can quantify the negative or positive impact from customers on system risk and provide them with charges or credits. But, the rate design in this method is based on the system planning projects and several system planning alternatives should be studied. Additionally, the charge rate is from the average cost of future investment and hence cannot reflect the incremental cost of every component incurred by different customers.

In paper [80], a novel pricing approach for reliability is proposed. It considers that each circuit has two functions: to allow power to be transmitted between two points and to assure the system reliability. Thus, the revenue of each circuit is obtained from two parts: the part considering the system use under normal states and the other part considering the system use under contingencies. The cost of the first part is priced based on MW-mile methodology. The unrecovered cost of circuits is then allocated among transactions according to a reliability index calculated with and without them. It could provide very low use-of-system cost and high reliability cost if systems are lightly used, devaluating the importance of network components in normal cases.

2.5.2 Pricing for Security at Distribution Level

Present planning standard in the UK requires that large users or user groups at distribution networks should be secured against N-1 contingencies [14], which should be captured by DNOs' distribution network charging models. Network security has also been reflected in some distribution system pricing models in the UK.

In FCP, both N-1 and N-2 level contingency analysis is carried out to assess the impact of all credible outages on DNOs' networks. It identifies which circuits and at what capacity need to be reinforced over the next 10 years through the analyses. This modeling approach is static and not updated if a reinforcement is required [81].

The LRIC model reported in [15] discussed in section 2.4.2 still does not elaborate the network security issue well, as it assumes that a branch needs to be reinforced when it is loaded up to 50%.

In the improved LRIC model in [76], each component is assigned with a contingency factor to reflect the amount of reserved capacity for contingencies, which is defined as the ratio of its maximum contingency flow in contingencies over its base flow in normal condition. Thus, the maximum allowed power flow each circuit can carry in normal conditions is computed as its rated capacity divided by its contingency factor

$$C = \frac{RatedCapacity}{ContingencyFactor} \tag{2-10}$$

2.6 Drivers for Change of Pricing for Security

Under the privatized context, both customers and network utilities seek to maximize their own profits. Thus, network customers might want to have, and utilities might be willing to provide, various security levels. This progress is stimulated by the advancement of smart grid.

2.6.1 Customers' Preference for Different Security Levels

Previously, users at the same busbar were supplied with uniform security levels and they had no other options. Although load shedding and shifting techniques can be utilized to create different security levels for users in contingencies according to their priorities, it is difficult to translate the different security levels into the needed network investment.

Under the new circumstances, customers would prefer diversified security levels to accommodate their own needs rather than being supplied with one overall security level [82]. Besides, in order to make electricity service security and reliability more of a private good, it is necessary to provide correct signals that reflect locational cost and enable customers to response to these prices through direct load response or through the choice of service levels [83]. Thus, the provision of one uniform security or reliability level for users and forcing them to pay for that is no longer acceptable.

As the advancement in control and communication technologies particularly due to the emergence of smart grid, it is possible for individuals to have different reliability levels and pay accordingly. Technically, it can be achieved by adopting load management techniques to increase the security or reliability demanded by some users and to decrease that of others.

This preference for different security can tremendously affect network planning, operation, and users' prospective behaviors. Hopefully, by encouraging more participation from them, network utilities can spare their potential investment and operate their networks more flexibly. For customers, they can have low prices for having less secure or reliable supply and get some sort of benefits in return for improving system security or reliability. Therefore, it is required that network pricing can reflect customers' preference and provide forward-looking to incentive their different choices.

2.6.2 Probabilistic Characteristics of Power Systems

Traditionally, network security recognized in pricing models for security is based on deterministic criteria, determined by assessing anticipated or unanticipated contingency events specified in the contingency lists produced by network planners or operators. This approach depends on the application of two criteria[84]:

- Credibility: the network configuration, outage events and operating conditions should be reasonably likely to occur;

- Severity: the outage event, network configuration and operating conditions on which the decision is based, should result in the most severe system performance.

This philosophy has served transmission and distribution system planning and operation well for a long period to ensure network security as it can provide higher reliability levels without too much calculation effort. The disadvantage with deterministic criterion is in that it can result in overly conservative decisions due to the emphasis on the most serious events. Those existing facilities driven by the most serious events might not be fully utilized from long-run perspective. Thus, networks can be overbuilt, leading to imprudent capital expenditure in network expansion.

Prudent capital expenditure should involve the application of risk management techniques, which are expected to include both the probability of an occurring event and its consequence. This leads to the probabilistic criteria which can recognize the probabilistic nature of power systems and alleviate the drawbacks of deterministic approaches as [85]:

- It considers the occurring probability of possible outages:
- It captures the increased risk caused by multiple constraints as it sums risk associated with all contingencies and problems;
- It can reflect the risk associated with the insecure regions;
- It considers the uncertainty under near future operating conditions.

Despite their merits, the progress of accepting probabilistic approaches is rather slow, mainly because they have not acquired the level of credibility compared with deterministic approaches which can provide much simpler and more transparent information. It would be preferable if the two criteria could be combined together to form a compromising criterion so that both of their merits are maintained.

2.6.3 Desirable Features of Pricing for Security

Most of the existing security/reliability oriented approaches are no longer fit for the new environment, as they only focus on network present status and passively reflect and allocate investment cost users among. They are unable to include potential investment to accommodate new customers and actively influence their behaviors.

The major disadvantage with FCP and LRIC for network security is that they treat all users equally for their use of the same piece of network component in contingencies, unable to discriminate the impact that contingencies have on different users. This is unfair for some users, who appreciate less security from particular components, but have to pay excessive charge. On the other hand, both the FCP model and the LRIC model are still based on deterministic criterion to examine customers' impact on network and determine prospective network investment. They are still unable to reflect the occurring probability of network contingencies and nodal unreliability tolerance.

Conceptually, network pricing models for security or reliability should not only have the features of long-run charging models outlined by Ofgem, but also have the features of being able to:

- Differentiate users' security preference;
- Price users based on their security levels;
- Actively influence customers' behaviors in favor of network security;
- Respect users' preference for different security levels;
- Reflect the probabilistic features of power systems.

2.7 Chapter Summary

This chapter firstly addresses the major arising changes that influence and drive network planning activities and the role of network charging is thereby introduced.

It then reviews a large number of existing pricing methodologies, including SRIC, SRMC, LRIC, and LRMC, with special attention paid to the charging models utilized in the UK. These models, however, are no longer fit for this new environment where a vast number of DGs emerge and customers are more willing to be interactive with networks. So, this chapter clarifies the major drivers for the reform in network charging especially for EHV distribution systems and introduces two newly proposed approaches - LRIC and FCP - for pricing EHV distribution networks in the UK to accommodate the new changes.

This chapter also addresses the importance of security in network planning and stresses that the related part of investment costs should be properly allocated among users. This standpoint is supported by a few pricing methodologies for security and reliability reported at transmission level.

This chapter finally outlines the rationale for change in charging for security at distribution level as those discussed models are not applicable to distribution systems any more. It also describes the desirable features of prospective distribution level pricing approaches for security.

Chapter 3

Network Pricing Using Marginal Approach

T**HIS** chapter proposes a new long-run marginal cost pricing using sensitivity analysis for revenue reconciliation to directly work out the impact from nodal injections on components.

3.1 Introduction

In this chapter, a novel long-run marginal cost (LRMC) charging method is proposed following the same principle of the model given in [15] mentioned in section 2.4.2, but utilizing sensitivity analysis to reduce the computational burden for large systems and provide a supplement to the original LRIC model. In the proposed LRMC approach, the change of present value of future reinforcement of a network component with respect to a nodal power increment is represented by three partial components:

- Sensitivity of components' loading levels with regard to nodal injections;
- Sensitivity of their reinforcement horizons with respect to their loading levels;
- Sensitivity of their present value of future reinforcement with respect to their reinforcement horizons.

By using this sensitivity approach, the LRMC model can produce charges through combining the three sensitivities. A simple test system is utilized to demonstrate the basic concept and an actual system taken from UK network is employed to test it. The research is carried out under different load growth rates (LGRs), loading levels and with different sizes of injections. The comparison shows the boundary conditions in which the two methods conform well, and in which the two depart and the LRMC model is no longer appropriate to be applied. In addition, in order to compare the economical signals provided by the two charging models to network users, tariffs reconciled from the LRIC and LRMC charges with two reconciliation methods, fixed adder and fixed multiplier, are also discussed.

3.2 Long-run Marginal Cost Pricing Model

The core of the LRIC method, which is also utilized in the new model, is to reflect:

- How a nodal injection might affect the level of spare capacity of network assets that support this injection;

- How the change in spare capacity would influence their investment horizons;

- How their change in investment horizon would impact their present value of future reinforcement of these assets.

These impacts can be approximated through three-step partial differentiations, which form the core of the LRMC model, given as

$$\frac{\partial PV_l}{\partial PI_n} = \frac{\partial PV_l}{\partial n_l} \cdot \frac{\partial n_l}{\partial P_l} \cdot \frac{\partial P_l}{\partial PI_n} \tag{3-1}$$

Where, P_l is the power flow along a circuit l linking nodes i and j, n_l is the circuit's reinforcement horizon, PI_n is the size of nodal injection at busbar n and PV_l is its present value of future reinforcement.

Mathematically, the LRMC pricing can be implemented through the following steps.

3.2.1 Sensitivity of Circuit Power Flow to Nodal Injection

Equation (3-2) represents active power flow along a circuit from bus i to bus j.

$$P_{ij} = V_i^2 \cdot G_{ij} - V_i \cdot V_j \cdot (G_{ij} \cdot \cos\theta_{ij} + B_{ij} \cdot \sin\vartheta_{ij}) \tag{3-2}$$

When a small injection PI_n connectes at node n, its effect on P_{ij} can be obtained by

$$\frac{\partial P_{ij}}{\partial PI_n} = \frac{\partial P_{ij}}{\partial V_i} \cdot \frac{\partial V_i}{\partial PI_n} + \cdot \frac{\partial P_{ij}}{\partial V_j} \cdot \frac{\partial V_j}{\partial PI_n} + \frac{\partial P_{ij}}{\partial \theta_i} \cdot \frac{\partial \theta_i}{\partial PI_n} + \frac{\partial P_{ij}}{\partial \theta_j} \cdot \frac{\partial \theta_j}{\partial PI_n} \tag{3-3}$$

Where, $\frac{\partial P_{ij}}{\partial V_i}, \frac{\partial P_{ij}}{\partial V_j}, \frac{\partial P_{ij}}{\partial \theta_i}$, and $\frac{\partial P_{ij}}{\partial \theta_j}$ can be calculated from (3-2) by calculating its partial derivates with regard to $V_i, V_j, \theta_i, \theta_j$.

In order to obtain the remaining parts in (3-3), sensitivity analysis is employed to represent the relationships between a change in nodal power and changes in voltage magnitudes and angles.

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial \theta} & \frac{\partial P}{\partial V} \\ \frac{\partial Q}{\partial \theta} & \frac{\partial Q}{\partial V} \end{bmatrix} \cdot \begin{bmatrix} \Delta \theta \\ \Delta V \end{bmatrix} = [J] \cdot \begin{bmatrix} \Delta \theta \\ \Delta V \end{bmatrix} \tag{3-4}$$

The analysis is based on the Jacobian matrix given in (3-4), which is obtained in the last iteration of power flow analysis. Finally, the effect from a power injection on circuits' power flows can be easily evaluated by applying (3-2)-(3-4).

3.2.2 Sensitivity of Time Horizon to Circuit Power Flow

Taking derivate of a circuit's original reinforcement horizon given in (2-2) with respect to circuit power flow gives

$$\frac{\partial n_l}{\partial P_l} = -\frac{1}{P_l \cdot \log(1+r)} \tag{3-5}$$

Apparently, for a given fixed LGR, the only factor that influences the sensitivity is the circuit's loading level: the negative sign implies that an increase in loading level reduces or brings forward time to reinforce and, a decrease in loading level increases or defers time to reinforce.

3.2.3 Sensitivity of Present Value to Time Horizon

Similarly, taking derivative of the circuit's present value in (2-3) with respect to its reinforcement horizon gives

$$\frac{\partial PV_l}{\partial n_l} = -\frac{Asset_l \cdot \log(1+d)}{\log(1+r)^{n_l}} \tag{3-6}$$

This formula represents how the change of its investment horizon affects its present value of future reinforcement. Because both asset cost and discount rate are fixed, the only factor influencing the level of sensitivity is the horizon. The negative sign indicates that a rise in the horizon lowers its present value of future reinforcement, and a fall in the horizon increases it.

3.2.4 Sensitivity of Present Value to Nodal Injection

Combining (3-3), (3-5) and (3-6) and replacing n_l with (2-2) leads to the sensitivity of present value of future reinforcement of a circuit with respect to the nodal injection

$$\frac{\partial PV_l}{\partial PI_n} = -\frac{PV_l}{P_l} \cdot \frac{\log(1+d)}{\log(1+r)} \cdot \left(\frac{P_l}{C_l}\right)^{\frac{\log(1+d)}{\log(1+r)}} \cdot \frac{\partial P_l}{\partial PI_n} \tag{3-7}$$

For a supporting circuit, its cost, the LGR, and the chosen discount rate are fixed. The factors that influence the change in its present value of future reinforcement as a result of the nodal injection are the circuit's loading level, the sensitivity of the circuit's loading level to the nodal injection. For circuits with low sensitivities of the flow change to the nodal injection, even if they are heavily loaded, they will still produce low charges, as the nodal injection causes very little change in their horizons. On the other hand, for lightly loaded circuits, if their sensitivities of flow change to the nodal injection are high, they will see larger charges for the node as the nodal injection triggers big change in their horizons. The predicted LGR is another factor affecting the calculated LRMC charges: a low LGR can lead to high charges and a high LGR, by contrast, can result in low charges, with the amount depending on the level of the circuit's utilization.

3.2.5 Long-run Marginal Cost

The LRMC charge for node n is the sum of costs over all circuits that support it multiplied by an annuity factor, given by,

$$LRMC_n = \sum_l \frac{\partial PV_l}{\partial PI_n} \cdot AnnuityFactor \tag{3-8}$$

3.3 Revenue Reconciliation

It should be noted that neither incremental nor marginal charges may be able to recover the revenue allowed for DNOs. Revenue reconciliation process is therefore generally required to adjust the nodal incremental or marginal prices so that the revenue recovered from network charges can meet the target revenue. The mechanisms used by DNOs are equally important due to the fact that in practice, a large proportion of their revenue may be recovered through such scaling mechanism and it may have a significant impact on the relative level of nodal tariffs.

There are two commonly adopted revenue reconciliation approaches to adjust the nodal prices, namely "fixed adder" and "fixed multiplier" [86]. The fixed adder method adds/subtracts a constant amount to/from the nodal charges to make up for the revenue shortfall/surplus. The multiplier method scales the nodal charges by a constant factor corresponding to the ratio of the target revenue to the recovered revenue. Equations (3-9) and (3-10) describe how they adjust nodal charges.

$$Tariff_i = Charge_i + Adder \tag{3-9}$$

$$Tariff_i = Charge_i \cdot (1 + Multiplier) \tag{3-10}$$

In the following two sections, the two methods are used to examine how the LRIC and LRMC models affect the tariffs.

3.4 Demonstration on a Two-busbar System

The comparison of the two long-run charging methods is firstly carried out on a simple network shown in Figure 3-1. It is supposed that the rating of L_f is 45MW after security redundancy and its cost is £3,193,400, which includes both asset cost and construction cost [15].Taking 6.9% discount rate and 40 years life span leads to its annuity cost as £236,760/yr.

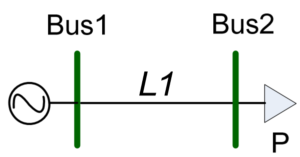

Figure 3-1 Layout of a two-busbar test system

As expected, the LRMC yields similar results with LRIC in both low and high LGR cases and at both low and high circuit loading levels, when LRIC charges are calculated with a small injection - 0.1MW.

Figures 3-2 and 3-3 compare the results with 1MW nodal injection for the LRIC model under two underlying growth rates, 1.5% and 5% respectively. Generally, the two kinds of charges are quite close at the most loading levels, with few exceptions. In the small LGR case, the charge difference grows with the increasing circuit's utilization. In the high LGR case, the charge difference decreases with the increase of loading level.

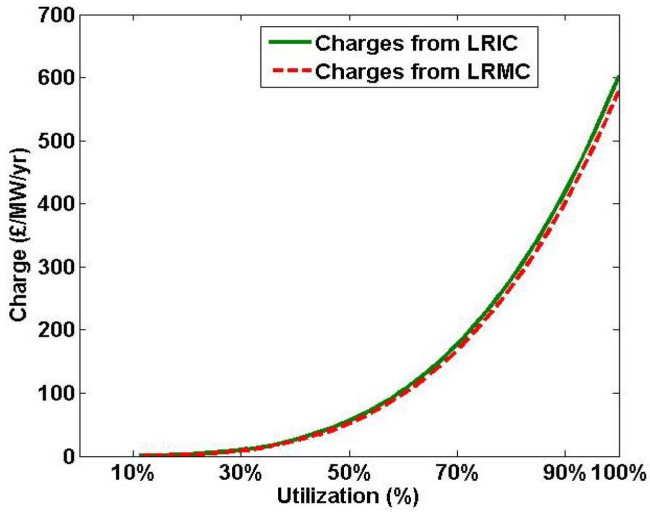

Figure 3-2 Charge comparison with 1MW injection for LRIC-1.5% LGR

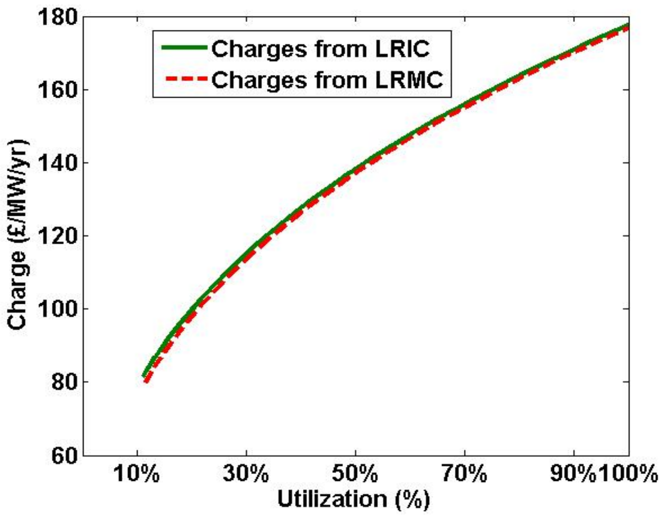

Figure 3-3 Charge comparison with 1MW injection for LRIC-5% LGR

The apparent difference in charges can be explained by the different calculation concepts of the two approaches, demonstrated in Figure 3-4. LRIC is achieved through simulating the difference in the present value of future reinforcement with and without an injection, whereas LRMC charge is calculated through a single function representing three partial differentiations initiated by the nodal injection. If the LRIC/LRMC cost function is not steep with respect to circuits' utilization, the difference between the two types of charges should be very small.

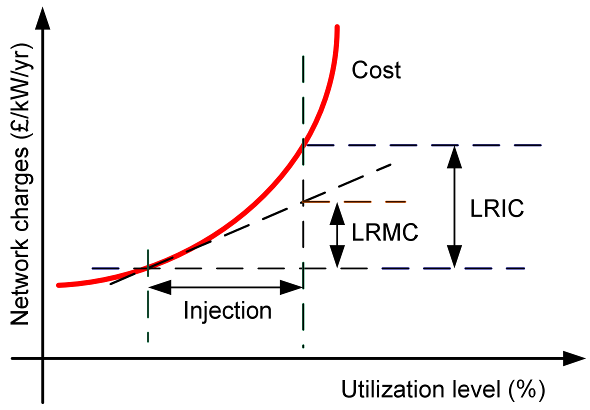

Figure 3-4 Different calculation concepts of LRIC and LRMC

Two three-dimensional Figures 3-5 and 3-6 demonstrate the charge difference under various LGR and circuit's loading level. As seen from, the large difference is seen when the LGR is lower than 1% and its utilization is higher than 70%.

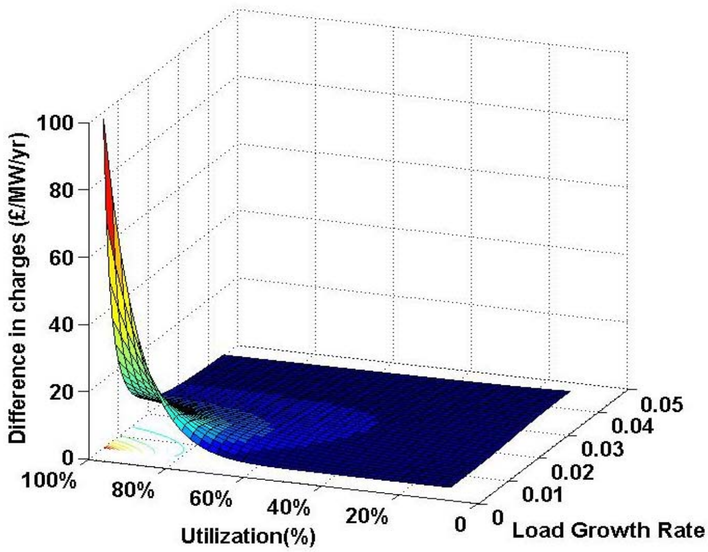

Figure 3-5 Difference in charges from the two methods-0.1MW injection

Figures 3-7 and 3-8 show the difference by varying the size of the nodal injection and the level utilization level of the circuit under two LGRs, 1.5% and 5%. Figure 3-7 shows that in the case of 1.5% LGR, the size of the nodal injection for LRIC has little influence on the difference when the circuit utilization is low, especially if it is smaller than 0.5MW. However, the difference grows apparent with the increasing nodal injection when the circuit's utilization is high. It is because that a big nodal injection can greatly bring forward the circuit's investment horizon. In the high LGR case given in Figure 3-8, big difference only appears when the injection is greater than about 0.5MW and the circuit's utilization is low. It is caused by the steep slope of the LRMC cost function with respect to component's loading level in Figure 3-4.

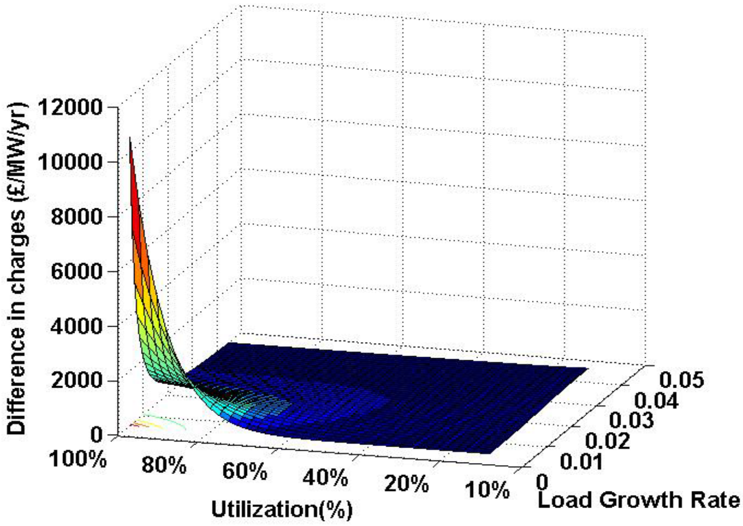

Figure 3-6 Difference in charges from the two methods-1MW injection

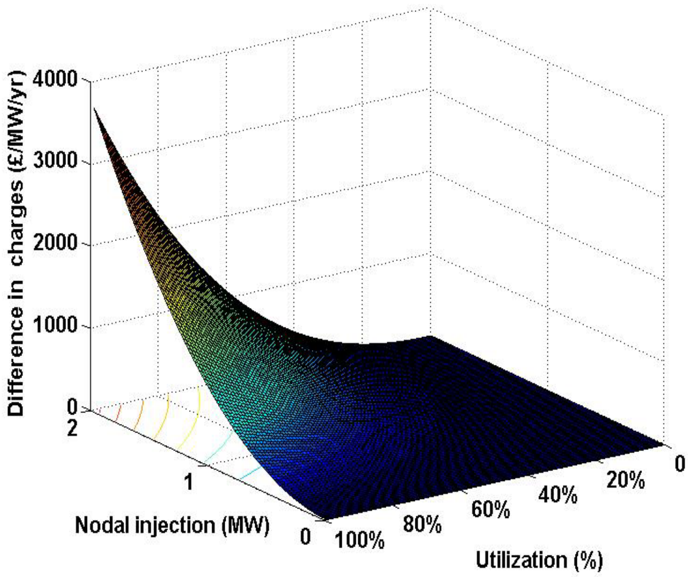

Figure 3-7 Difference in charges from the two methods-1.5% LGR

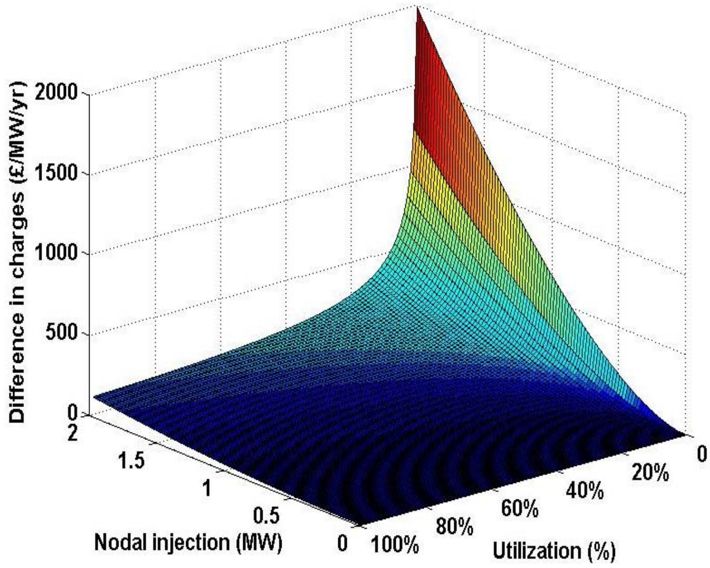

Figure 3-8 Difference in charges from the two methods-5% LGR

3.5 Demonstration on a Practical System

In this section, the comparison of the LRIC and LRMC pricing methods is carried out on a practical grid supply point area given in Appendix. A.

The rationale in comparing the two methods on a practical system is that a nodal increment is likely to impact many circuits in the network. The difference between the two methods for each circuit might be modest, but accumulating these differences over all supporting circuits for a node could potentially produces large difference. The comparison is carried out in two conditions:

- Two underlying LGRs: 1% and 5%;
- Two loading levels: base loading level and scaled-up level (by 20%).

An injection of 1MW is employed for the LRIC model. The comparisons are in terms of nodal LRIC and LRMC charges and tariffs.

As for time efficiency of evaluating this practical system, it takes the LRIC model 157 milliseconds to calculate the nodal charges for every single node in the network. But for the LRMC model, it only takes 51milliseconds on the same computer - 1/3 of the computational effort of the LRIC. For a large-scale system with 2000 nodes, it takes the computer 12 seconds to calculate LRIC charge for a single node and approximately 6 hours and 40minutes in total. In contrast, it takes only 0.5 second to compute LRMC charges for a single node and takes barely 17 minutes in total.

3.5.1 Base Loading Level Case

In the UK, system winter peak demand is higher than summer peak demand and it triggers network reinforcement. Therefore, the demand in this case is chosen as system peak in winter, without any scaling.

Table 3-1 gives the nodal charges from LRIC and LRMC approaches under the base loading level. To assist analysis, Figure 3-9 depicts the utilization levels of the branches in base loading case. As seen, the most heavily loaded circuit is line No. 4 linking bus 1008 and bus 1006. Transformers 12-17 also have high loading levels.

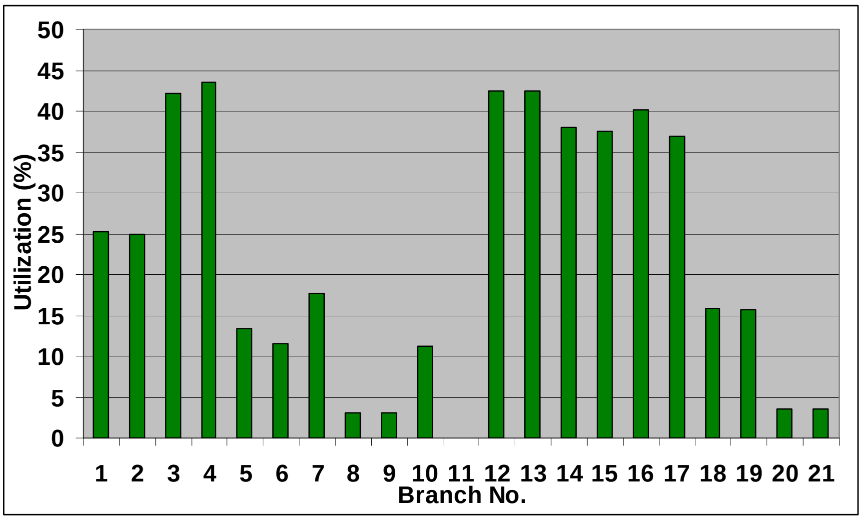

Figure 3-9 Circuit utilization in base loading level case

It can be seen from Table 3-1, when LGR is at 1%, the charge differences are large for nodes 1001-1007, as they are supported by relatively highly utilized circuits. It can, also be observed that nodes 1009-1015 have nearly 0 charges, as they are supported by lightly loaded circuits. In the 5% LGR case, the charges at nodes 1009-1015 become significantly larger because when the underlying LGR is higher, the investment horizons of their supporting components become nearer and therefore a nodal injection would have greater impact on their present value of future investment. In comparison, nodes 1003-1006 are supported by heavily utilized circuits, their charges decrease as the LGR increases. Generally, the conclusions from the simple example are still applicable here: cases with small LGRs and high loading levels would see big a difference.

Table 3-1 Comparison of charges under two load growth rates (£/kW/yr)

Bus No.	LGR=1%			LGR=5%		
	LRIC	LRMC	Difference	LRIC	LRMC	Difference
1001	4.265	3.82	0.444	5.886	5.84	0.042
1002	0.607	0.546	0.061	4.419	4.39	0.03
1003	20.21	19.06	1.149	10.14	10.10	0.049
1004	18.61	17.61	1.001	9.04	8.997	0.04
1005	1.963	1.75	0.211	1.285	1.275	0.01
1006	18.16	17.18	0.979	6.698	6.66	0.039
1007	1.963	1.752	0.211	1.285	1.275	0.01
1009	0.122	0.097	0.025	10.16	10.02	0.143
1010	0.025	0.019	0.006	6.116	5.974	0.142
1011	0.245	0.16	0.085	12.94	12.61	0.329
1012	0.241	0.157	0.084	11.43	11.14	0.292
1013	0	0	0	2.053	1.961	0.092
1014	0	0	0	1.242	1.15	0.092
1015	0	0	0	2.3	2.121	0.179

The adder and fixed multiplier are employed here to demonstrate the degree of adjustments required to meet the target revenue, their relative merits and impacts on LRIC and LRMC charges. The resultant tariffs are given in Tables 3-2 and 3-3.

Table 3-2 Comparison of tariffs using fixed adder method (£/kW/yr)

Bus No.	LGR=1%			LGR=5%		
	LRIC	LRMC	Difference	LRIC	LRMC	Difference
1001	6.659	6.806	-0.147	11.073	11.073	0
1002	3.001	3.532	-0.531	9.606	9.623	-0.017
1003	22.604	22.046	0.558	15.327	15.333	-0.006
1004	21.004	20.596	0.408	14.227	14.230	-0.003
1005	4.357	4.736	-0.379	6.472	6.508	-0.036
1006	20.554	20.166	0.388	11.885	11.893	-0.008
1007	4.357	4.738	-0.381	6.472	6.508	-0.036
1009	2.516	3.083	-0.567	15.347	15.253	0.094
1010	2.419	3.005	-0.586	11.303	11.207	0.096
1011	2.639	3.146	-0.507	18.127	17.843	0.284
1012	2.635	3.143	-0.508	16.617	16.373	0.244
1013	2.394	2.986	-0.592	7.240	7.194	0.046
1014	2.394	2.986	-0.592	6.429	6.383	0.046
1015	2.394	2.986	-0.592	7.487	7.354	0.133

From Table 3-2 the largest difference in LRIC and LRMC tariffs is 0.592£/kW/yr for nodes 1013-1015, when LGR is 1%,. It is because that although these nodes have zero charges, fixed adder allocates the under-recovered revenue equally to all network nodes, thus resulting in the fixed adder of £2.394/kW/yr for LRIC and £2.986/kW/yr for LRMC. When LGR increases to 5%, the largest difference decreases to 0.284£/kW/yr (for node 1011). For all other nodes, the charges from the LRIC and LRMC approaches yield quite similar tariffs. Compared with 1% LGR case, tariffs in this case are much higher, because rapid load growth can bring the components' reinforcement horizons nearer, thus leading to high charges. From the Table, it can also be seen that the fixed adder approach maintains the relative differences in nodal tariffs the same as the nodal charges, therefore minimizing the potential distortion to the economic signals.

Table 3-3 Comparison of tariffs using fixed multiplier method (£/kW/yr)

Bus No.	LGR=1%			LGR=5%		
	LRIC	LRMC	Difference	LRIC	LRMC	Difference
1001	5.342	5.134	0.208	10.600	10.592	0.008
1002	0.760	0.734	0.026	7.958	7.962	-0.004
1003	25.315	25.617	-0.302	18.261	18.318	-0.057
1004	23.311	23.668	-0.357	16.280	16.318	-0.038
1005	2.459	2.352	0.107	2.314	2.312	0.002
1006	22.747	23.090	-0.343	12.062	12.079	-0.017
1007	2.459	2.355	0.104	2.314	2.312	0.002
1009	0.153	0.130	0.023	18.297	18.173	0.124
1010	0.031	0.026	0.005	11.014	10.835	0.179
1011	0.307	0.215	0.092	23.303	22.871	0.432
1012	0.302	0.211	0.091	20.584	20.204	0.38
1013	0.000	0.000	0	3.697	3.557	0.14
1014	0.000	0.000	0	2.237	2.086	0.151
1015	0.000	0.000	0	4.142	3.847	0.295

As for the fixed multiplier method, it amplifies the relative difference of nodal charges; as a result, higher charges getting even higher tariffs and 0 charges remaining 0, as shown in Table 3-3. For the low LGR case, the biggest difference in LRIC and LRMC tariff is 0.357 £/kW/yr for node 1004, which has been reduced from the original difference of 1.001£/kW/yr in charge, as LRIC and LRMC methods see different multipliers, 0.25 for LRIC and 0.34 for LRMC. When it comes to the high LGR case, the tariffs reconciled from LRIC and LRMC charges are quite close and the biggest difference is 0.433£/kW/yr for node 1011. Compared with the difference of 0.329£/kW/yr in charges (in Table 3-1), this tariff difference is amplified by the multiplier. Potentially, if there are few excessively high nodal charges, a modest multiplier would lead to extremely high tariffs for the few nodes.

3.5.2 Higher Loading Level Case

In this part, all loads are scaled up by 20%, thus increasing all circuits' utilization by approximately 20%. All branches' scaled up loading levels are given in Figure 3-10.

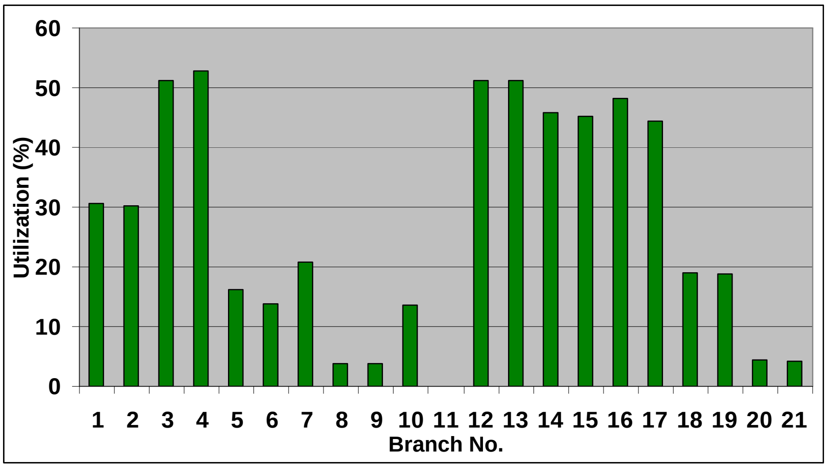

Figure 3-10 Circuit utilization in scaling loading level case

Table 3-4 summarizes the charges from the two charging approaches under two LGR cases. Obviously, charges follow the same patterns as the base case, but they are much higher caused by the increased circuit utilization levels. Compared with results given in Table 3-1, the increments in charges are similar for both approaches: lower LGRs case sees greater increments in charges and high LGRs scenario witnesses smaller charge increments.

Table 3-4 Comparison of charges under two load growth rates (£/kW/yr)

Bus No.	LGR=1%			LGR=5%		
	LRIC	LRMC	Diff.	LRIC	LRMC	Diff.
1001	12.52	11.43	1.087	6.29	6.25	0.037
1002	1.757	1.61	0.146	4.70	4.68	0.026
1003	60.19	57.35	2.836	10.87	10.83	0.044
1004	55.21	52.76	2.451	9.66	9.62	0.036
1005	5.39	4.894	0.496	1.38	1.38	0.008
1006	53.87	51.47	2.398	7.16	7.12	0.035
1007	5.39	4.89	0.496	1.38	1.36	0.008
1009	0.39	0.32	0.068	11.21	11.08	0.134
1010	0.076	0.06	0.014	6.57	6.45	0.125
1011	0.78	0.54	0.237	14.45	14.14	0.314
1012	0.77	0.53	0.233	12.85	12.56	0.282
1013	0	0	0.000	2.18	2.10	0.082
1014	0	0	0.000	1.31	1.23	0.083
1015	0	0	0.000	2.43	2.27	0.162

As for the tariffs from the fixed multiplier method given by Table 3-6, they become a little smaller for all nodes because of the increased demand, by comparison with the results in Table 3-3. Unlike the fixed adder approach, this method produces no negative tariff in the 1% LGR case. All tariffs reconciled by this approach are smaller than the charges provided in Table 3-3 as smaller fixed multipliers scale down all charges proportionally.

Table 3-5 provides tariffs calculated using fixed adder method. In the low LGR case, the fixed adder approach gives negative tariffs for some nodes. It is due to that charges are dominated by the high charges at buses 1003, 1004 and 1006. The revenue recovered from these three nodes alone already exceeds the allowed revenue. Consequently, a negative adder is obtained, leading to negative tariffs for the majority of other nodes in the system. When the LGR rises up to 5%, tariffs for all nodes are positive because of the calculated positive adder and the difference in tariffs also becomes small compared with the 1% LGR case.

Table 3-5 Comparison of tariffs using fixed adder method (£/kW/yr)

Bus No.	LGR=1%			LGR=5%		
	LRIC	LRMC	Difference	LRIC	LRMC	Difference
1001	-5.196	-4.834	-0.362	9.036	9.042	-0.006
1002	-15.959	-14.654	-1.305	7.446	7.472	-0.026
1003	42.474	41.086	1.388	13.616	13.622	-0.006
1004	37.494	36.496	0.998	12.406	12.412	-0.006
1005	-12.326	-11.370	-0.956	4.126	4.172	-0.046
1006	36.154	35.206	0.948	9.906	9.912	-0.006
1007	-12.326	-11.374	-0.952	4.126	4.152	-0.026
1009	-17.326	-15.944	-1.382	13.956	13.872	0.084
1010	-17.640	-16.204	-1.436	9.316	9.242	0.074
1011	-16.936	-15.724	-1.212	17.196	16.932	0.264
1012	-16.946	-15.734	-1.212	15.596	15.352	0.244
1013	-17.716	-16.264	-1.452	4.926	4.892	0.034
1014	-17.716	-16.264	-1.452	4.056	4.022	0.034
1015	-17.716	-16.264	-1.452	5.176	5.062	0.114

The revenue reconciliation mechanism used by a DNO is very important as it decides how LRIC or LRMC charges should be shaped into tariffs seen by network users. In practice, a large proportion of DNOs' revenue may be recovered through the mechanism. The fixed adder approach can maintain the same level of differentiation between nodal tariffs, thus minimizing any distortion over the pure incremental/marginal costs. In contrast, the fixed multiplier approach maintains the relativity between nodal tariffs, but the relativity is proportionally amplified by the same level. This could be considered as the distortion of the cost signals that network customers would see. Thus, the fixed adder approach is preferred by the majority of DNOs in the UK [68].

Table 3-6 Comparison of tariffs using fixed multiplier method (£/kW/yr)

Bus No.	LGR=1%			LGR=5%		
	LRIC	LRMC	Difference	LRIC	LRMC	Difference
1001	4.436	4.276	0.16	8.767	8.769	-0.002
1002	0.622	0.602	0.02	6.551	6.566	-0.015
1003	21.325	21.454	-0.129	15.150	15.194	-0.044
1004	19.560	19.737	-0.177	13.464	13.497	-0.033
1005	1.910	1.831	0.079	1.923	1.936	-0.013
1006	19.086	19.254	-0.168	9.979	9.989	-0.01
1007	1.910	1.829	0.081	1.923	1.908	0.015
1009	0.138	0.120	0.018	15.624	15.545	0.079
1010	0.027	0.022	0.005	9.157	9.049	0.108
1011	0.276	0.202	0.074	20.140	19.838	0.302
1012	0.273	0.198	0.075	17.910	17.621	0.289
1013	0.000	0.000	0	3.038	2.946	0.092
1014	0.000	0.000	0	1.826	1.726	0.1
1015	0.000	0.000	0	3.387	3.185	0.202

3.6 Chapter Summary

In this chapter, a novel LRMC charging method based on analytical approach is proposed, which directly relates the nodal power increment to the change in components' present value of future network investment. Results of two systems using the proposed method are compared and contrasted with those from the LRIC approach. Based on the extensive analysis, the following key findings can be listed:

- In terms of accuracy, the LRIC and LRMC approaches yield quite similar results when the sizes of the nodal injections for LRIC are small. The biggest difference appears when circuits are highly loaded and LGR is small. When injections become large, the discrepancies between the two approaches become apparent and the biggest difference shows up when circuits are lightly loaded and LGR is high. As for tariffs, they are highly dependant on charges, and largely follow the same pattern of charges.

- In terms of speed, the LRIC needs to run power flow analysis twice for each nodal injection in order to examine the effects of an injection on the long-term development costs. For a large system, the computational burden grows exponentially with the increase in the size of networks. The proposed LRMC, on the other hand, saves significant computational time for large-scale networks by utilizing sensitivity analysis, avoiding running power flow analysis for every nodal injection.

- In terms of flexibility, the LRIC model, working through simulation approach, can examine the impact imposed on a network by any size of injection. But, the proposed LRMC can only accurately represent a very small change. For large injections, the charges obtained with LRMC can deviate from those calculated with the LRIC.

- Finally, revenue reconciliation process is very important in how it might shape the relative difference in LRIC and LRMC charges. The fixed adder approach uniformly scales up/down all nodal charges, hence preserving the absolute difference in nodal charges. The fixed multiplier, on the other hand, amplifies the nodal relativity. If the amplification becomes significant, it could considerably distort the impact that a nodal power injection might have on network development cost. As a consequence, the industry in general favors the fixed adder approach over the fixed multiplier.

Chapter 4

Network Pricing Considering Impact of Security

THIS chapter examines the impact of security of supply on network charging by recognizing how an injection would affect components in network contingencies.

4.1 Introduction

The LRIC model given in section 2.4.2 calculates charges by reflecting the change in assets' spare capacity due to a nodal increment and then translating it into changes of assets' annuitized cost. It assumes that a component needs to be reinforced when it is 50% loaded, as the left spare capacity is reserved for coping with network contingencies. The improved LRIC approach in [76] also recognizes the importance of network security in charging by reshaping components' maximum available capacity with contingency factor. The shortcoming of this model is that it only examines the impact from the injection on system assets in normal conditions, ignoring contingency cases, regardless how great the impact could be. This cannot truly reflect the reality, since in contingencies the injection could also bring forward or defer components' investment horizons and influence the final charges.

This chapter also stresses the impact of contingencies on components and it should be reflected in network charging. It tries to capture the impact of nodal injections on components in both normal and contingency situations. This chapter first examines the impact of a nodal injection on an asset's investment horizon in both normal and contingency situations for three typical networks. The smaller one from the two conditions is selected as the actual investment horizon. Sensitivity analysis is also introduced to save computational burden. The proposed approach is finally demonstrated and compared with the original charging model in [76].

4.2 Reinforcement Horizons in Normal Conditions

This section introduces the determination of components' reinforcement horizons in normal cases without and with injections for three typical networks.

4.2.1 Original Reinforcement Horizon without Injections

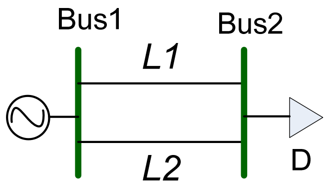

Figure 4-1 Two-busbar radial system framework

For a simple network in Figure 4-1, if either of the two identical circuits fails, D at busbar 2 can still be secured by the other working circuit. There is no need to reinforce it as long as the curtailed load amount from D does not exceed its rated capacity under a given load growth rate, *r*. In N-1 contingency, such as L2 fails, L1 needs to pick up L2's normal case flow to avoid any load curtailment. It means that L1's normal case flow can only increase on top of the capacity reserved for catering for the flow along L2, which is reflected by reshaping its capacity with its contingency factor [76]. Thus, L1's reinforcement horizon can be identified by examining the time taking the load flow along it to grow from current loading level to its maximum available capacity,

$$\frac{RC}{CF} = D_l \cdot (1+r)^n \tag{4-1}$$

where, *RC* is L1' rated capacity, *CF* is its contingency factor and D_l is its current loading level.

Rearranging and taking logarithm of it gives,

$$n = \frac{\log\left(RC/CF\right) - \log(D_l)}{\log(1+r)} = \frac{\log C - \log D_l}{\log(1+r)} \tag{4-2}$$

Where, *C* is its maximum available capacity.

4.2.2 New Reinforcement Horizon with Nodal Injections

When a new nodal increment comes to busbar 2, the two circuits' new horizons change, which can be obtained by replacing $\log D_l$ in (4-2) with $\log(D_l + \Delta P)$

$$n_{new} == \frac{\log C - \log(D_l + \Delta P)}{\log(1+r)} \tag{4-3}$$

where, ΔP is the normal flow change along each of the circuits due to the increment.

4.3 Reinforcement Horizons in Contingencies

In contingencies, network connectees' impact on components can also be assessed similarly by examining the change in components' spare capacity due to the connections and then translating it into the change of their investment horizons.

4.3.1 Original Reinforcement Horizon without Injections

For the simple two-busbar system given in Figure 4-1, if no new connectee is connected to bus 2, L1's investment horizon when L2 fails, can be determined with

$$n_{cont} = \frac{\log RC - \log D_{cont}}{\log(1+r)} \tag{4-4}$$

where, D_{cont} is L1's maximum contingency flow.

Rearranging (4-4) gives

$$n_{cont} = \frac{\log\left(RC \big/ D_{cont} \right)}{\log(1+r)} = \frac{\log\left(\frac{RC}{CF} \Big/ \frac{D_{cont}}{CF} \right)}{\log(1+r)} = \frac{\log\left(C \big/ D_l \right)}{\log(1+r)} \tag{4-5}$$

Obviously, this formula is the same as (4-2), indicating that a component's original horizon under contingencies without any injections is equal to its normal case one.

4.3.2 New Reinforcement Horizon with Nodal Injections

When a new connectee comes to busbar 2, there will be an incremental contingency flow along L1, supposed to be ΔP_{cont}. Under this condition, L1's new reinforcement horizon will change to

$$n_{cont,new} = \frac{\log RC - \log\left(D_{cont} + \Delta P_{cont}\right)}{\log(1+r)} \tag{4-6}$$

Rearranging above formula gives,

$$n_{cont,new} = \frac{\log C - \log\left(D_1 + \frac{\Delta P_{cont}}{CF}\right)}{\log(1+r)} \tag{4-7}$$

By comparison (4-3) and (4-7), it is noticed that only when the circuit's normal flow change is equal to its contingency flow change divided by its contingency factor are the same the two new reinforcement horizons.

4.4 Comparison of the Two New Horizons

In order to investigate the difference between the two new horizons from normal and contingency conditions, an extensive comparison is carried out on three typical network frameworks: single component, parallel components and meshed networks.

4.4.1 Demand Supported by a Single Component

If a load is supported by a single component, its supply will be interrupted when the component fails, leading to a contingency factor of 1 for the component. So, its new reinforcement horizon from both normal and contingencies are the same.

4.4.2 Demand Supported by Parallel Components

For a load supported by two identical parallel components as depicted in Figure 4-1, if DC load flow is used and power loss along the circuits are ignored, their new reinforcement horizons from the two conditions should be the same. It is because the contingency case flow increment is 2 times of that in normal case, which is thereafter scaled down by their contingency factors of 2.

In practice, however, the parallel components might be not necessarily identical and even if they are identical, their contingency factors might not be 2 if the power loss along them is considered. Thus, their new horizons from the two cases would differ from each other, decided by their normal case and contingency case loading conditions, and contingency factors.

4.4.3 Demand Supported by Meshed Networks

For the case that loads are supported by a meshed network, such as given in Figure 4-2, the situation becomes complex. In order to simplify analysis, the three circuits and the two loads are assumed to be the same respectively. Here, only L1's new horizons due to an injection at busbar 2 are analyzed.

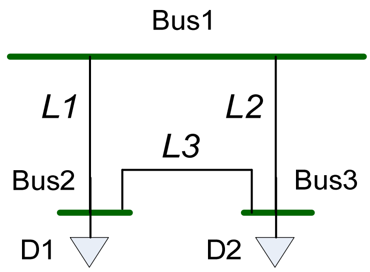

Figure 4-2 Three-busbar meshed system framework

In normal conditions, L1's future reinforcement is only triggered by the load growth at bus 2, as the load growth at bus 3 has no impact on it. Its most serious contingency is L2's failure, which doubles its loading level as load D2 is transferred to it.

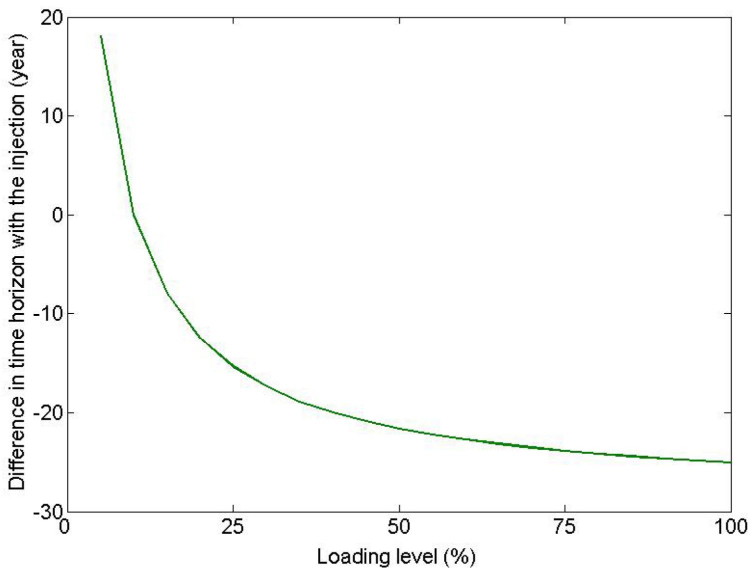

Figure 4-3 Difference in time horizon for L1

Figure 4-3 depicts the difference of L1's two new reinforcement horizons with the rise in its loading level: normal case horizon minus contingency case horizon. As seen, when it is lightly loaded, the normal case horizon is bigger than the contingency one, and the difference decreases with increasing loading level. It means that in low loading conditions, L1's future reinforcement is driven by contingency situations. With the rise in its loading level, a cross point is reached at a loading level of 15%, beyond which the contingency becomes bigger than the normal case one. It indicates that at higher loading levels, L1's reinforcement is triggered by normal situations.

One particular case should be pointed out is the change of L3's horizon when load D1 and D2 are not with the same size. If D2 is bigger than D1, L3's normal case flow moves from busbar 2 to busbar 3 and an injection at busbar 2 could decrease the flow. So, L3's new normal case reinforcement horizon driven by injection busbar 2 is deferred. When its most serious contingency happens, i.e. L2 fails, an injection at busbar 2 has no impact on L3 at all. Hence, L3's contingency case horizon due to the connectees at busbar 2 is always smaller than its normal case one. This special case, however, cannot be properly recognized by the original model, as it only investigates a connectee's impact in normal case.

It is seen that a component's normal and contingency reinforcement horizons would be dramatically different in meshed networks. The proposed concept can capture and differentiate connectee's impact in both conditions, so it should be able to improve charge assessment in distribution networks especially EHV distribution networks, where a large umber of meshed networks exist.

4.5 New Charging Model

4.5.1 New Charging Model Framework

This charging framework takes components' new reinforcement horizons under both normal and contingency situations into consideration so as to more precisely capture users' impact. The smaller one between the two is chosen as their actual horizons. The main procedures of this charging model are outlined below:

Base Case Analysis

Base case flow analysis is to determine components' base status without any injections and feed the results into horizon evaluation. Their original horizons can be determined with either (4-2) or (4-4), as they generate the same results.

Incremental Flow Analysis

Incremental normal case flow analysis seeks to calculate flow changes along all components due to small injections and then to calculate their normal case horizons. The new reinforcement horizons with nodal injections in normal conditions are determined with (4-3). Their new horizons in contingencies are calculated with (4-7). Here, for each component, the injections' impact should be assessed in the most serious contingency events that drivers their future investment. Hence, a large number of contingencies should be analyzed in order to find the most serious ones.

Unit price calculation

Once the old and new horizons are indentified for each circuit, they are submitted into the following steps to derive unit charges.

The present value of future reinforcement of a component is

$$PV = \frac{Cost}{(1+d)^{n}} \tag{4-8}$$

where, d is the chosen discount rate, and n is the component's investment horizon.

The change in present value as a result of a nodal increment for the component is

$$\Delta PV = Cost \cdot \left(\frac{1}{(1+d)^{n_{new}} - (1+d)^{n}} \right) \tag{4-9}$$

The incremental cost of the component will be the annuitized change in its present value of future investment

$$\Delta IC = \Delta PV \cdot AnnuityFactor \tag{4-10}$$

The nodal incremental cost for a node is the accumulation of the present values of incremental cost of all its supporting components, given as

$$LRIC = \frac{\sum \Delta IC}{\Delta PI} \tag{4-10}$$

where, ΔPI is the injection size at the node.

4.5.2 Sensitivity Analysis to Determine Flow Difference

As seen from part 4.5.1, a large number of runs of incremental power flow and incremental contingency flow analysis should be carried out in order to decide in whether normal or contingency situations connectees have greater impact on components. It is immensely time-consuming for large-scale systems. An alternative approach is to adopt sensitivity analysis to determine how a tiny injection would change components' flow in both conditions, which has been utilized in Chapter 3. This approach is not only time-saving but also able to provide quite satisfactory results especially when the injection is vey small [17]. In normal conditions, sensitivity analysis is executed based on the base case power flow, and in contingencies, sensitivity analysis is carried out based on each selected contingency case.

4.6 Three-busbar System Demonstration

4.6.1 Charge Assessment

In this section, the enhanced model is demonstrated and compared with the original security-oriented model on the simple network given in Figure 4-2. The three circuits are assumed to be identical, each with the rated capacity and cost of 45 MW and £1,596,700 respectively. D1 and D2 are chosen as 10 MW and 20MW, both of which have a growth rate of 2.0%. An injection of 1MW is utilized. The calculated results under N-1 contingencies for the three circuits with and without an injection are provided in Table 4-1.

As seen, although the three circuits are identical, their contingency factors and maximum allowed capacity vary dramatically. L2 has the smallest contingency factor, 1.8, leading to the biggest allowed capacity of 25MW. L3's contingency factor is the biggest, 6.0, which scales its maximum allowed capacity down to merely 7.5MW. Big contingency factors mean that they should carry a large volume of contingency flow, which in turn leads to small capacity available in normal conditions.

Table 4-1 Results of the three-busbar system

Circuit No.	L1	L2	L3
Normal flow (MW)	13.33	16.67	3.33
Maximum contingency flow (MW)	30	30	20
Most serious contingency	L2 out	L1 out	L2 out
Contingency factor	2.25	1.80	6.0
Maximum allowed capacity (MW)	20	25	7.5
Biggest contingency flow change over contingency factor (injection at bus 2) (MW)	0.44	0.56	0.0
Normal flow change (injection at bus 2) (MW)	0.67	0.33	-0.33
Biggest contingency flow change over contingency factor (injection at bus 3) (MW)	0.44	0.56	0.17
Normal flow change (injection at bus 3) (MW)	0.33	0.67	0.33

When an injection connects to busbar2 or busbar 3, its impact on the three circuits are quite different in both normal and contingency conditions. When it connects to either bus 2 or bus 3, all circuits' maximum contingency flow increments are 1MW in their most contingencies. For example, when L2 fails, the injection at busbar 2 will increase both L1 and L3's contingency flow by 1MW. In normal conditions, however, an injection at busbar 2 causes the three circuits' normal flow rise by 0.67MW, 0.33MW and -0.33MW respectively. The negative increment means that the injection can reduce L3's flow. In contingencies, by contrast, the contingency flow increments along the circuits over their contingency factors become to 0.44MW, 0.56MW and 0.0MW respectively. By comparison, the injection has greater impact on L1 in normal conditions, which is exactly reverse for L2. As regard to L3, the power increment has no impact on it in contingencies, whereas it brings down its flow in normal conditions.

To further elaborate the difference in the results from the two approaches, the three circuits' reinforcement horizons are provided in Table 4-2.

As expected, the two approaches produce the same new results when no injections are connected. With new injections considered, the changes in the circuits' reinforcement horizons are decided by the changes in their loading levels: bigger positive increment brings down components' reinforcement horizons even further. For example, when an injection is at busbar 2, L1's normal case and contingency case horizons are changed to 35.85yrs and 37.45yrs respectively. By contrast, L1' normal case horizon is 38.27yrs when an injection is at busbar 3, but it is brought down to 37.45yrs in contingencies. One point should be noted is that when an injection connects to busbar 2, L3's contingency horizon is equal to its original horizon, 81.50yrs, smaller than the normal horizon of 92.09yrs. It means that the injection does not affect L3 in contingencies but defers its horizon in normal conditions.

Table 4-2 Reinforcement horizons considering both conditions (yr)

Circuit No.		L1	L2	L3
No injection	Normal case	40.75	40.75	81.50
	Contingency case	40.75	40.75	81.50
Injection at Bus 2	Normal case	35.85	38.76	92.09
	Contingency case	37.45	37.45	81.50
Injection at Bus 3	Normal case	38.27	36.81	71.92
	Contingency case	37.45	37.45	76.59

The details of cost and total charge for the two load busbars derived using the horizons in Table 4-2 are outlined in Table 4-3.

Table 4-3 Results of the three-busbar system (£/MW/yr)

		Cost from L1	Cost from L2	Cost from L3	Total charge
Proposed approach	Bus 2	3019.87	1918.78	0.00	4938.66
	Bus 3	1918.78	2347.17	460.42	4726.37
Original approach	Bus 2	3019.87	1108.01	-260.69	3867.19
	Bus 3	1405.06	2347.17	460.42	4212.65

For both approaches, a large proportion of the charge for busbar 2 is from the cost of L1, and for busbar 3, it mainly comes from the cost of L2, as injections at the two buses greatly bring up their loading levels, in whatever normal or contingency situations. One interesting point is that the cost from L3 on busbar 2 is zero in the proposed approach, as an injection at busbar 2 does not change L3's reinforcement horizon. The original model, however, produces a cost of -260.69£/MW/yr, from L3 for busbar 2. It is unreasonable as although an injection at busbar 2 can bring down L3's normal case horizon, it has on impact on L3's reinforcement in the contingency that drives it future reinforcement, i.e. L2 fails.

As the new model chooses the smaller new horizons to derive the cost, it produces bigger cost from all three circuits and consequently the final total charges for the two busbars compared with original model. The ultimate nodal charges are 4938.66£/MW/yr at bus 2 and 4726.37£/MW/yr at bus 3 from the new model, higher than 38.67.19£/MW/yr and 4212.65£/MW/yr from the original model respectively.

4.6.2 The Impact of Different Influencing Factors

Three major factors that affect final charges are, loading level, load growth and nodal injection size, and the impact of them on the charge difference is examined intensively in this part. In order to simplify analysis, the load at busbar 3 is assumed to be 2 times of that at busbar 2 and only the charge for busbar 2 is investigated.

Figure 4-4 shows that with the increase of system loading conditions, the charge difference widens gradually. When the load amount at busbar 1 is over 11MW, the difference grows bigger than 1837.628 £/MW/yr, which becomes even large with the rise in loading level. The cause is that higher loading levels produce nearer reinforcement horizons, hence leading to higher charges and greater difference.

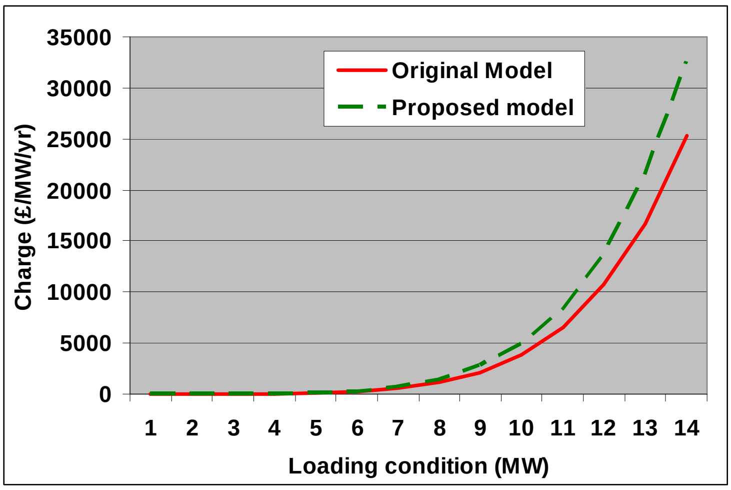

Figure 4-4 Charge comparison under different loading levels

Figure 4-5 demonstrates the change in the difference with respect to the rise of load growth rate. The difference is relatively small when the load growth rate is smaller than about 0.4%, while it grows steadily when load growth rate is over 1%. One important point is that when the load growth rate is approximately 1.6%, the charges from the original model decrease after a summit is reached. It is because the load at busbar 2 would have even greater negative cost, i.e. reward, for using L3, and beyond that rate, the total charges are gradually reduced. By contrast, the proposed model produces consistent increasing charges with the rise of load growth rate, as no costs from circuits are negative.

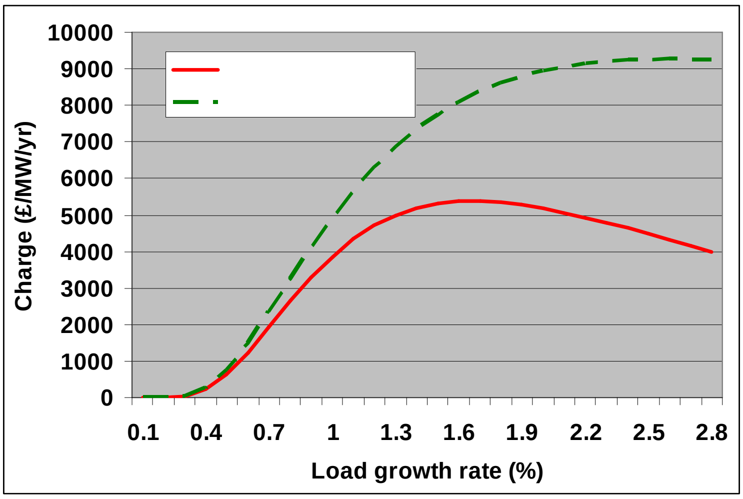

Figure 4-5 Charge comparison under different load growth rates

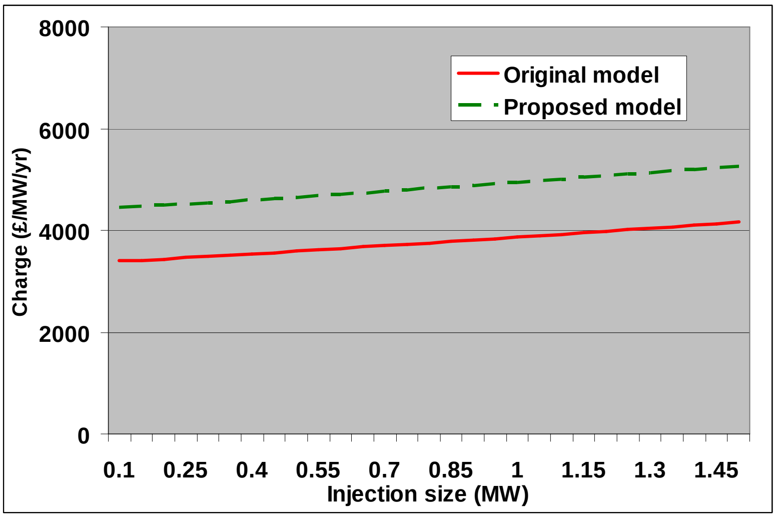

Figure 4-6 Charge comparison under different injection size

With regard to the injection size for the LRIC model, it also influences the difference as demonstrated in Figure 4-6. When the injection size is small, the difference tends to be small as well and it grows slightly when the injection becomes bigger.

4.7 Demonstration on an actual network

In this section, the demonstration of the new model is carried out on a practical system taken from the UK network, given in Appendix. A. The discount rate and load growth rate are chosen as 2.0% and 6.9% respectively. The system is also supposed to withstand N-1 contingencies. An injection of 0.01MW size is selected. The circuit No. 11 linking busbars 1005 and 1007 is not going to be accounted in charge evaluation, as it is owned by the generator at busbar 1002.

Table 4-4 Contingency factors and maximum allowed capacity of all circuits

No.	Contingency factor	Maximum allowed capacity (MVA)	No.	Contingency factor	Maximum allowed capacity (MVA)
L1	1.99	24.95	L12	2.05	14.04
L2	2.01	24.71	L13	2.05	14.04
L3	2.05	26.77	L14	2.04	19.59
L4	1.98	27.66	L15	2.07	19.33
L5	3.77	16.21	L16	1.95	16.06
L6	2.04	17.95	L17	2.12	14.76
L7	1.93	12.32	L18	2.00	19.97
L8	2.05	9.31	L19	2.04	19.65
L9	2.05	9.30	L20	2.02	14.21
L10	2.07	17.49	L21	2.03	14.19

All components' contingency factors and their reshaped maximum allowed capacity from the original model are given in Table 4-4. As noticed, the contingency factors for those parallel components are not necessarily 2 as they are not exactly identical and the loss along them is also considered. Circuit No.5 has the biggest contingency factor of 3.77, which consequently cuts its maximum allowed capacity is cut from 61.16MVA down to merely 16.21MVA. The maximum allowed capacity of all other branches is also brought down in proportion to their contingency factors.

To assist analysis, Figure 4-7 provides all branches' utilization levels. The most heavily loaded circuit is L2 linking buses 1004 and 1006, and by contrast, L3 has the smallest loading level, merely approximately 14%. These loading conditions are calculated on the base of the circuits' rated capacity and they might be even higher if assessed on the basis of their maximum available capacity.

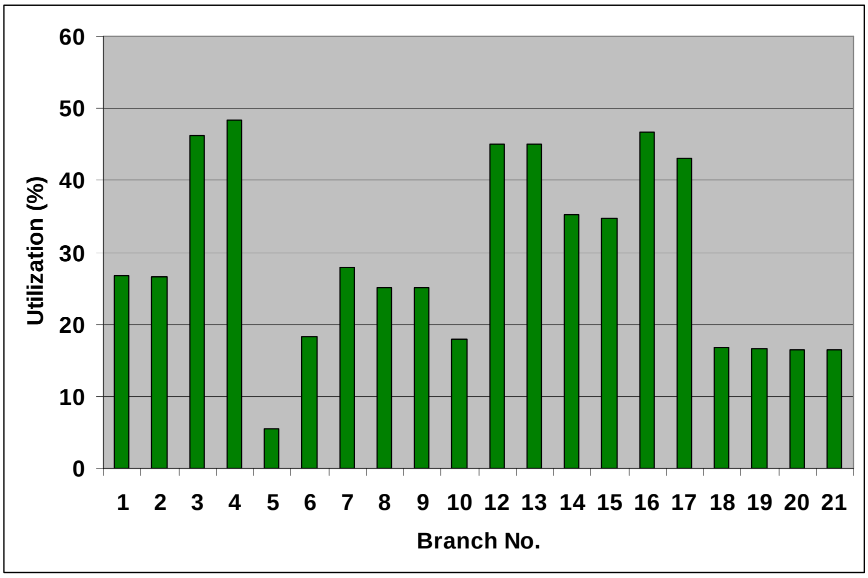

Figure 4-7 Base case circuit utilization levels

Table 4-5 gives the active power change along all branches in normal conditions and the change in most contingency situations over their contingency factors (in order to simplify quotation, this part of change is referred as contingency flow change in the following parts).

When an injection connects to busbar 1001, its three supporting branches, L1, L13 and L14 have bigger normal case flow changes than the changes in their contingency flow. One exception is L2, which has a bigger extra contingency flow change, counted as 5.0377×10^{-3}MW. An injection at busbar 1003 can cause greater normal case flow changes for its supporting circuits, L3, L5, L14, and L15. For example, L5's normal flow change is 5.0345×10^{-3}MW, which is almost 2 times of the contingency flow change, 2.6852×10^{-3}MW. The reason is that although L5's biggest extra contingency flow change is approximately 0.01MW when L3 fails, it has a quite bigger contingency factor, 3.77, which can dramatically bring down the contingency flow change. One point should be noted is that an injection at busbar 1006 can reduce

L5' normal case flow by -4.7285×10^{-3}MW, but it has no impact on it in contingencies. Big extra power flows can bring components' reinforcement horizons closer, zero extra flows cause no impact at all, and negative extra flows mean that components' reinforcement horizons are deferred. Generally, small difference between the two case flow changes means that they are more likely to generate similar components' reinforcement new horizons, whereas big difference would widen them.

Table 4-5 Comparison of active power flow change (10^{-3}/MW)

1001	Circuit No.	L1	L2	L13	L14	
	Normal case	5.0854	5.0332	5.0260	5.0261	-
	Contingency case	5.0847	5.0377	4.9353	4.9355	-
1003	Circuit No.	L3	L4	L5	L14	L15
	Normal case	5.1206	5.0648	5.0345	5.0624	4.9988
	Contingency case	5.0077	5.1724	2.6852	4.9620	4.8961
1006	Circuit No.	L3	L4	L5		
	Normal case	4.7548	5.2983	-4.7285	-	-
	Contingency case	4.9403	5.0951	0.0000	-	-
1007	Circuit No.	L16	L17			
	Normal case	5.2271	4.8116	-	-	-
	Contingency case	5.1856	4.7644	-	-	-
1009	Circuit No.	L6	L7	L10	L18	L19
	Normal case	5.0390	5.0062	4.9926	5.0242	4.9865
	Contingency case	4.9530	5.2393	4.8583	5.0059	4.9267
1013	Circuit No.	L8	L9	L20	L21	
	Normal case	5.0185	5.0098	5.0087	5.0000	-
	Contingency case	4.9138	4.9049	4.9562	4.9473	-

The power flow changes along a branch due to a nodal injection in both conditions are decided by several factors, such as system topologies, component parameters, system loading levels, contingency types, as well as injection sizes. Although the difference of the results in Table 4-5 is not huge, more complex networks could have quite diversified results. A load that withdraws power at a busbar which is located far from power sources can have greater impact on the components closer to the sources as the power loss along all supporting circuits accumulates gradually. However, it is not easy to tell directly in which situations an injection could have greater impact on a component. Therefore, simulation approach needs to be carried out to determine the impact and it is undoubtedly time-consuming.

As proposed, it could be more easily to carry out sensitivity analysis to capture injections' impact to save computational effort. The sensitivity coefficients from normal and contingency cases that reflect how an injection affects components' flow are given in Table 4-6.

Table 4-6 Sensitivity analysis under the two conditions (10^{-3}/MW)

	Circuit No.	L1	L2	L13	L14	
	Normal case	5.085	5.033	5.025	5.025	-
	Contingency case	5.084	5.038	4.938	4.938	-
1003	Circuit No.	L3	L4	L5	L14	L15
	Normal case	5.121	5.065	5.035	5.062	4.999
	Contingency case	5.010	5.172	2.685	4.967	4.900
1006	Circuit No.	L3	L4	L5		
	Normal case	4.755	5.298	-4.728	-	-
	Contingency case	4.941	5.095	0.000	-	-
1007	Circuit No.	L16	L17			
	Normal case	5.226	4.810	-	-	-
	Contingency case	5.186	4.764	-	-	-
1009	Circuit No.	L6	L7	L10	L18	L19
	Normal case	5.039	5.006	4.993	5.024	4.986
	Contingency case	4.953	5.239	4.858	5.005	4.926
1013	Circuit No.	L8	L9	L20	L21	
	Normal case	5.019	5.010	5.008	4.999	-
	Contingency case	4.914	4.905	4.956	4.947	-

The sensitivities reflect circuits' flow changes caused by one unit nodal injection at the studied busbars. By comparing, sensitivity analysis produces quite close results with those in Table 4-5 from simulation method. For example, the sensitivities at busbar 1003 also demonstrate that an injection connection to this bus can have greater impact on L1, L13 and L14 in normal conditions, but less on L2 in normal cases. The contingency case sensitivity for L5 seen from busbar 1003 is 2.685×10^{-3}MW and the normal case one is 5.035×10^{-3}MW, showing the same pattern as given in Table 4-5. Further, the impact from an injection at busbar 1006 on L5 can also be captured by the sensitivities: it reduces L5's normal flow, but causes no impact on it in contingencies. Although it cannot provide results as precise as simulation approach, sensitivity analysis is able to produce very closer results especially when injection size is small.

By using the power changes in Tables 4-5 or 4-6, all components' new reinforcement horizons under the two conditions can be easily derived, given in Table 4-7.

Table 4-7 Components' new horizons from the two conditions (yr)

1001	Circuit No.	L1	L2	L13	L14	
	Normal case	34.7316	34.7036	6.9729	6.9697	-
	Contingency case	34.7317	34.7035	6.9733	6.9701	-
1003	Circuit No.	L3	L4	L5	L14	L15
	Normal case	7.3565	7.3818	34.4117	12.7984	12.7535
	Contingency case	7.3567	7.3816	34.4262	12.7987	12.7539
1006	Circuit No.	L3	L4	L5		
	Normal case	7.3573	7.3813	34.4719	-	-
	Contingency case	7.3569	7.3818	34.4427	-	-
1007	Circuit No.	L16	L17			
	Normal case	7.8986	7.7886	-	-	-
	Contingency case	7.8988	7.7888	-	-	-
1009	Circuit No.	L6	L7	L10	L18	L19
	Normal case	52.8960	33.5071	53.0635	57.8360	57.8374
	Contingency case	52.8967	33.5053	53.0646	57.8361	57.8379
1013	Circuit No.	L8	L9	L20	L21	
	Normal case	36.5565	36.5513	58.5115	58.5087	-
	Contingency case	36.5577	36.5525	58.5121	58.5093	-

The difference in the two new horizons is highly dependent on the flow difference given in Table 4-5 or 4-6. Bigger flow difference causes greater difference. One interesting point is that the load at busbar 1006 can defer L5's horizon from 34.4427yrs to 34.4719yrs in normal conditions, leading to a negative cost -0.7048£/kW/yr, i.e. a reward, for using L5, whereas in contingencies, the cost becomes to zero.

The accumulated charges for the six load busbars from the two approaches are outlined in Table 4-8.

Table 4-8 Charges obtained using the two methods (£/kW/yr)

Busbar No.	1001	1003	1006	1007	1009	1013
Original method	6.372	18.860	15.515	2.461	8.938	6.638
Proposed method	6.373	19.013	16.559	2.461	9.256	6.638

For busbars 1001, 1007 and 1013, they are supported by two groups of similar parallel branches and the two approaches produce almost the same charges. It is because that an injection connecting to them tends to produce similar impact on them in normal and contingency situations. As for busbar 1009 which is supported by non-similar parallel components, its charge difference grows to 0.318£/kW/yr. Busbars 1003 and 1006 supported by meshed networks witness even greater charge difference: 0.157£/kW/yr for bus 1003 and 1.04£/kW/yr for bus 1006.

Generally, the charges from the proposed approach are always not smaller than those from the original model. The charge difference tends to grow even bigger, with the increase in loading conditions and the decrease in load growth rate.

4.8 Chapter Summary

This chapter proposes an enhanced charging model over the existing security-oriented LRIC by considering an injection's impact on network components in both normal and contingency conditions. The smaller new horizons from the two situations are selected to derive charges. Based on the intensive analysis, the following key observations can be outlined:

- In terms of reflectivity, the original LRIC charging model reflects the impact from network users on network components in contingencies by introducing contingency factor to shape components' maximum available capacity. Its scope is rather narrow as it only considers the impact in normal conditions. The proposed approach, on the other hand, can recognize the impact in contingencies and thus, it should be able to even truly reflect the impact from network users on components and allocate the cost.

- In term of difference, results vary dramatically, depending on many factors, such as the topology and operation conditions of the networks. The original model only chooses the normal case horizons to derive charges, whereas the proposed method chooses the smaller calculated new horizons from the two conditions to calculate nodal charges. Thus, the charges from this new approach are always not smaller than those from the original model.

- In terms of simplicity, the original model needs one run power flow analysis, one full contingency analysis, and N runs of incremental power flow analysis (the number of which is decided by the number of studied busbars) to assess injections' impact. Apart from these calculations, the proposed approach still needs to run full incremental contingency analysis to capture injections' impact in contingencies. Sensitivity analysis in both normal and contingency situations can be harnessed to assist analysis. Its advantage is in that it can directly work out the extent to which a tiny injection would affect network components instead of running power flow and incremental contingency flow repeatedly. It produces quite similar results with those from the simulation approach as long as the injection size is small for the simulation approach.

- As for influencing factors, loading level, load growth rate, and injection size are three major factors affecting the charge difference from the original and the proposed approaches. Higher loading levels, larger load growth rates and bigger injection sizes can enlarge the difference. It also means that the original model could produce misleading charges under these circumstances that cannot truly reflect users' impact.

Chapter 5

Network Pricing For Different Security Levels

THIS chapter proposes a new charging model for security of supply by dividing demand at each busbar into interruptible and uninterruptible parts to assess their impact on components.

5.1 Introduction

In a deregulated environment, network customers may prefer higher or lower security level rather than the uniform levels provided by network utilities [82]. In order to make electricity service reliability more of a private good, it is also necessary to provide correct signals that reflect locational and temporal cost and enable customers response to these prices through direct load response or through the choice of service levels [83]. Therefore, security-oriented charging models should be cost-effective not only in terms of being able to reflect the extent of the use of the network by customers but also in terms of respecting their security preference.

This chapter proposes a new long-run pricing model to price users according to their security preference. Loads at all busbars are first classified into interruptible and uninterruptible compositions: the interruptible part should be secured in normal conditions, but can be curtailed in contingencies; on the contrary, the uninterruptible part should be secured under contingencies. By examining the impact from the two load compositions on the future network investment cost over time, the long-run incremental cost for each node can be calculated based on the extent to which they defer or bring forward the time horizon of network components. The proposed approach is able to reflect and respect users' security level preference. The generated locational charges can thus serve as economic messages to influence users' behaviors in: 1) the choice of security levels of supply, 2) connections sizes and 3) connection sites. The approach is demonstrated and compared with the original security-based charging model [76] on two test systems in terms of magnitude of charges for the two types of load.

5.2 Load Composition Classification

With regard to security levels of supply to users, some of them might prefer securer supply to reduce the probability of loss of load; some, on the contrary, might want less secure supply in order to spare expense; others might prefer that part of their demand can be interrupted in contingencies, but the rest is secured. Network charging models should be able to respect network users' choices and treat them properly.

According to this philosophy, demand connected at each busbar can be categorized into uninterruptible part and interruptible part:

- The uninterruptible load composition is the part of demand that must be secured during any contingencies, regardless of whether the contingency is unanticipated component's failure or anticipated planned maintenance. In normal conditions, this part should be satisfied as well. This definition is also applicable to the prospective growth of this type of load.

- The interruptible load composition is the part of demand that can be interrupted in contingencies, but must be secured in normal conditions. It is also applicable to the future growth of this part demand.

The role and importance of interruptible demand has already been recognized in [87, 88] in order to promote network security and flexible operation. By adopting this scheme, DNOs can resort to interruptible demand not only in contingencies circumstances but also under alert circumstances to make more flexible operation so as to defer potential reinforcement along with increasing economic and social benefit. Furthermore, by introducing this concept into network charging, users' are provided with the options to different security levels of supply.

5.3 Charging for Different Load Compositions

According to the classification of load composition, in order to truly recognize users' different preference for security level of supply, not only normal conditions but also contingency conditions should be taken into consideration. The role and importance of component's spare capacity to the two compositions under both normal and contingency circumstances is first elaborated. Then, a novel charging strategy is proposed accordingly to price users based on their different security level preference by examining their impact on network components in two situations. It seeks to reflect the variation in present value of future reinforcement of network assets due to the connection of interruptible and uninterruptible loads.

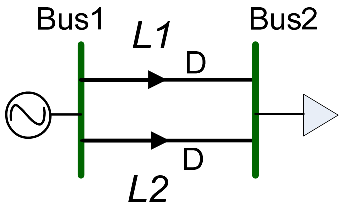

Figure 5-1 Layout of a two two-busbar test system

5.3.1 Original Investment Horizon without Injection

For a simple two-busbar system given in Figure 5-1, it is supposed that the two circuits are identical. Each carries a flow of D, which can be classified into two parts: interruptible part, D_{inter}, and uninterruptible part, D_{unint}. In normal conditions, their investment horizon under a given load growth rate can be indentified with

$$RC = D \cdot (1+r)^{n_{new}} = (D_{unint} + D_{inter}) \cdot (1+r)^{n_{new}} \tag{5-1}$$

where, RC is their rating and r is the chosen load growth rate.

Rearranging and taking logarithm of it gives

$$n_{norm} = \frac{\log(RC) - \log(D_{unint} + D_{inter})}{\log(1+r)} \tag{5-2}$$

Under an N-1 contingency event, such as L2 fails, L1 only needs to accommodate the uninterruptible load along the two circuits as the interruptible load can be curtailed. Hence, L1's investment horizon is calculated with

$$n_{cont} = \frac{\log(RC) - \log(D_{unint,cont})}{\log(1+r)} \tag{5-3}$$

where, $D_{unint,cont}$ is the maximum uninterruptible flow along L1 in the contingency, which should be 2 times of D_{unint} here.

As seen, in normal conditions, the circuit's investment horizon is driven by both interruptible and uninterruptible flows along it, whereas only triggered by the uninterruptible flow in contingencies. As each component can have only one original investment horizon, the smaller one between the above two horizons is selected as its actual one.

5.3.2 New Investment Horizon due to Interruptible Injection

If an interruptible injection is connected to busbar 2, its impact on the circuits can be reflected through examining the change in their investment horizons as well.

In normal conditions, if ΔP is the incremental flow along L1 due to the new interruptible connectee, the two circuits' new horizons can be determined with

$$RC = (D + \Delta P) \cdot (1 + r)^{n_{norm,new}} \tag{5-4}$$

Rearranging above formula and taking logarithm of it gives

$$n_{norm,new} = \frac{\log(RC) - \log(D + \Delta P)}{\log(1 + r)} \tag{5-5}$$

In normal conditions, L1 also needs to take up the uninterruptible flow part along L2 when L2 fails. It means that L1 should be able to accommodate the maximum uninterruptible flow along it in the case that L2 fails. Thereby, the new injection can only increase on top of the potential maximum contingency flow, leading to their new reinforcement horizon determined by replacing D in (5-5) with $D_{unint,cont}$

$$n_{cont,new} = \frac{\log(RC) - \log(D_{unint,cont} + \Delta P)}{\log(1 + r)} \tag{5-6}$$

For the two components, their new reinforcement horizons with the incorporation of the interruptible injection should be the smaller one between (5-5) and (5-6).

5.3.3 New Investment Horizon due to Uninterruptible Injection

If a new uninterruptible connectee comes to busbar 2, it also impacts the two circuits in both normal and contingency situations. In normal conditions, its influence is the same as an interruptible connectee, leading to the two circuits' new horizons which can be evaluated with (5-5). When L2 fails, L1 only needs to accommodate the uninterruptible flow along it, which leads to its new reinforcement horizon

$$RC = (D_{unint,cont} + \Delta P_{cont}) \cdot (1 + r)^{n_{cont,new}} \tag{5-7}$$

where, ΔP_{cont} is the incremental uninterruptible flow change along L1 due to the uninterruptible connection in contingency situations.

Similarly, (5-7) can be rewritten as

$$n_{cont,new} = \frac{\log(RC) - \log(D_{unint,cont} + \Delta P_{cont})}{\log(1+r)} \tag{5-8}$$

Their new horizons with an interruptible injection connected are the smaller one between (5-5) and (5-8).

5.3.4 Unit Price for New Connectees

Unit price for different load compositions is evaluated by assessing the change in components' present value of future reinforcement.

The present value of future reinforcement of a component is calculated as

$$PV = \frac{Cost}{(1+r)^n} \tag{5-9}$$

where, d is discount rate, n is its original reinforcement horizon without any nodal injection.

By replacing n with new investment horizon, n_{new}, its new present value of future investment is obtained, which leas to its change in present value

$$\Delta PV = Cost \cdot \left(\frac{1}{(1+d)^{n_{new}}} - \frac{1}{(1+d)^n} \right) \tag{5-10}$$

The incremental cost of the component will be the annuitized change in its present value of future investment horizon as a result of the injection, given by

$$\Delta IC = \Delta PV \cdot AnnuityFactor \tag{5-11}$$

The LRIC charge for a studied node, i, is evaluated by reviewing the change in annuitized present value of future reinforcement cost of all its supporting components

$$LRIC_i = \frac{\sum IC}{\Delta PI_i} \tag{5-12}$$

where, ΔPI_i is the injection size at node i.

5.3.5 Implementation Procedures

This new charging model seeks to reflect and differentiate customer's different preference and price them according to their different impact in both normal and contingency situations. The overall detailed implementation procedures are summarized as follows.

- Determine original flows in normal conditions and maximum uninterruptible contingency flows under all considered contingencies along all components in the case without any injection. The original normal flows are obtained by running power flow analysis; the maximum uninterruptible contingency flows are evaluated by removing all interruptible load parts and then running contingency analysis.

- Determine incremental flows along all components due to new interruptible and uninterruptible connectees in normal and contingency circumstances. In normal conditions, the increment flows caused by the interruptible and uninterruptible injections can be easily obtained by running power flow by connecting a tiny increment connected to the studied nodes. Uninterruptible increment's effect in contingencies is determined by: 1) first removing all interruptible loads; 2) and then running incremental contingency flow under all contingency events with a tiny uninterruptible injection connected to the studied nodes.

- Calculate all components' original reinforcement horizons, which are the smaller between (5-2) and (5-3).

- Calculate all components' new reinforcement horizons with nodal injections. With an interruptible increment connection, their new horizons are the smaller one between (5-5) and (5-6); and for the case with an uninterruptible load connection, their new horizons are the smaller one between (5-5) and (5-8).

- Calculate unit prices for all studied nodes. Once the two time horizons are indentified for each circuit, their unit prices for both the interruptible and uninterruptible loads can be assessed by submitting the horizons obtained in above steps into (5-9)-(5-12).

Unlike the original charging model which produces one charge at each busbar, this method produces two nodal charges at each studied busbar: one is for interruptible loads and the other is for uninterruptible loads. The diversified charges should be able to differentiate users' security preferences and reflect their prospective behaviors.

5.4 Demonstration on a Small System

In this section, the two-busbar system in Figure 5-1 is utilized to demonstrate the proposed concept. It is assumed that the two circuits are identical, each with the rated capacity of 45MW and cost of £1596700. A discount rate of 6.9% is taken, which is commonly accepted as minimum acceptable rate of return by DNOs in the UK Load growth is set as the project long-term rate in the U.K, 1%. The proportions of interruptible and uninterruptible loads at busbar 2 are 20% and 80% respectively, leading to the same proportions of interruptible and uninterruptible flows along the two circuits under normal conditions.

5.4.1 Charge Evaluation under Different Loading Levels

In normal conditions, either circuit can be maximally loaded up to their full capacity, 45MW, leading to a sum of 90MW loading capability. Under N-1 contingency, the only one circuit's rated capacity can be utilized to accommodate the uninterruptible load, whose maximum size is only 45MW. By adopting the proposed model, the original reinforcement horizons of the two circuits at four different loading levels are valuated, given in Table 5-1.

In both situations, the two circuits' reinforcement horizons become small with the increase in demand. At each loading level, network contingencies can even greatly bring forward the horizons as each circuit needs to pick up extra contingency flows. At 40MW loading case, the normal case horizon is 81.50yrs, which is dramatically brought down to merely 34.26yrs. Hence, the circuits' actual original reinforcement horizons are those obtained in contingency situations.

Table 5-1 Original horizons without injection

Size of D (MW)	Horizon (normal) (yr)	Horizon (contingency) (yr)
10	220.82	173.58
20	151.16	103.92
30	110.41	63.17
40	81.50	34.26

Table 5-2 provides the circuits' new investment horizons and the resultant charges for the interruptible load at busbar 2 with an interruptible injection at it under the two conditions. Compared with normal conditions, contingencies could dramatically reduce the circuits' new horizons, especially at higher loading levels. For example, at 40MW loading level with 8MW interruptible load, the normal case investment horizon is 79.02yrs, which decreases to 32.71yrs under contingencies. As for the charges outlined in the last column, they are rather low when loading conditions are light: merely 1.04£/MW/yr when interruptible load is 2MW. They increase exponentially with the rise in circuit loading level, soaring to 2454.14£/MW/yr at 8MW interruptible loading level.

Table 5-2 Results for interruptible load composition

Size of D (MW)	Interruptible part of D (MW)	New Horizon (normal) (yr)	New Horizon (contingency) (yr)	Annual charge (£/MW/yr)
10	2	211.24	167.49	1.04
20	4	146.26	100.83	49.18
30	6	107.11	61.10	482.54
40	8	79.02	32.71	2454.14

The two circuits' new investment horizons along with the calculated charges in the case with an uninterruptible injection connected to busbar 2 at four loading levels are shown in Table 5-3. Similarly to the previous case, heavy loading cases lead to nearer horizons in the two conditions with contingency horizons even lower. The generated charge is merely 2.48£/MW/yr when the uninterruptible load is 8MW, but jumps to 5133.48£/MW/yr when the uninterruptible load grows to 32MW.

Table 5-3 Results for uninterruptible load composition

Size of D (MW)	Uninterruptible part of D (MW)	New Horizon (normal) (yr)	New Horizon (contingency) (yr)	Annual charge (£/MW/yr)
10	8	211.24	161.75	2.48
20	16	146.26	97.83	107.64
30	24	107.11	59.07	1024.64
40	32	79.02	31.17	5133.48

By comparison charges in Tables 5-2 and 5-3, it is noticed that at all loading levels, charges for interruptible loads are smaller than those for uninterruptible loads and the difference widens with rising loading levels.

In order to elaborate charge difference and compare them with those from the original security-orientated LRIC model, results from it are outlined in Table 5-4.

Table 5-4 Results from the original charging model

Size of D (MW)	New Horizon (normal) (yr)	New Horizon (contingency) (yr)	Annual charge (£/MW/yr)
5	151.16	141.58	8.22
10	81.50	76.59	370.88
15	40.75	37.45	3573.5
20	11.84	9.36	18011.54

In the original model, one circuit can only maximum loaded to 22.5MW, with a total of 45MW, as the two circuits' capacity is halved with a contingency factor of 2. In both normal and contingency conditions, new horizons are smaller than those from the previous two cases, leading to even higher charges. At 10MW loading level (total supported load by the two circuits is 20MW), the charge is 370.88£/MW/yr, approximately 370 times of the charge for interruptible load (1.04£/MW/yr) and 150 time of the charge for the uninterruptible load (2.48£/MW/yr). At 20MW loading level (total supported load is 40MW), the difference soars even extremely higher.

As seen from Tables 5-2 to 5-4, charges at the same loading levels for the interruptible loads are always the smallest, followed by charges for the uninterruptible loads, and the charges generated by the original approach are the highest. The different charges for interruptible and uninterruptible loads can reflect their security levels.

As seen from this example, the maximum amount of load supported in the original model is only 45MW, smaller than that in the proposed model, as the two circuits' rated capacity is halved by the contingency factor of 2, leaving 50% of capacity unused. The new model, by contrast, can maximally support 45MW uninterruptible load and a certain amount of interruptible, depending on the two load compositions.

5.4.2 Charge Comparison under Different Load Compositions

This section compares the charges from the two approaches under various load compositions under different scenarios.

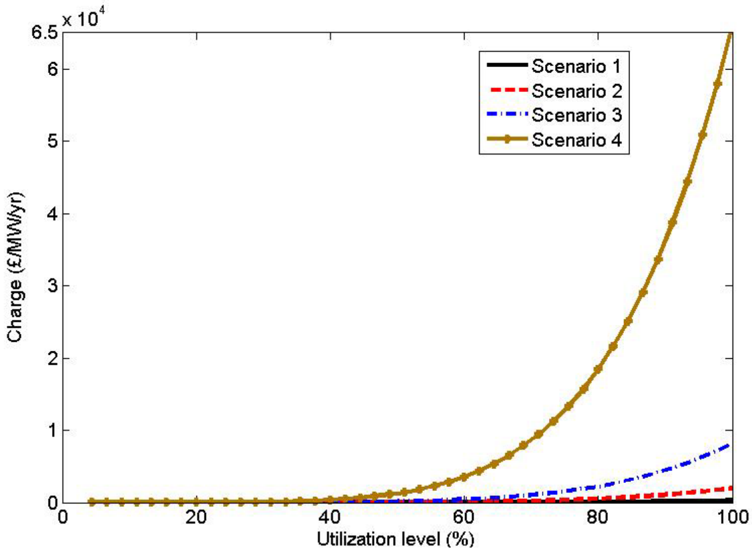

Figure 5-2 Charges for interruptible load under different scenarios

Figure 5-2 compares charges for interruptible loads under four scenarios with different interruptible load proportions: scenario 1: 50%, scenario 2: 30%, scenario 3: 10% and scenario 4: 0% (this is the case of the original model). As seen, charges increase exponentially with the rise in circuits' loading levels in all four scenarios. When the interruptible load proportion is high, its charge is fairly low, as demonstrated in scenario 1. However, the decrease of its proportion tremendously propels the charges, as shown in scenario 3, which produces greater charges than scenarios 1 and 2 at the same loading levels. Yet, scenario 4 generates the highest charges, in which the proportion of interruptible load is zero.

The actual maximum load amount at busbar 2 the two circuits can support is quite different in the four scenarios. In all four cases, the maximum uninterruptible load which can be supported is 45MW, i.e. the capacity of one circuit. But the maximum supported interruptible load diversifies: scenario 1: 45MW, scenario 2: 19.3MW, scenario 3: 6MW, and scenario 4: 0MW. It is because less spare capacity can be utilized by interruptible loads, with the rising proportion of uninterruptible loads. The proposed model allows more interruptible load to be served, unlike the original model which assumes all loads are uninterruptible.

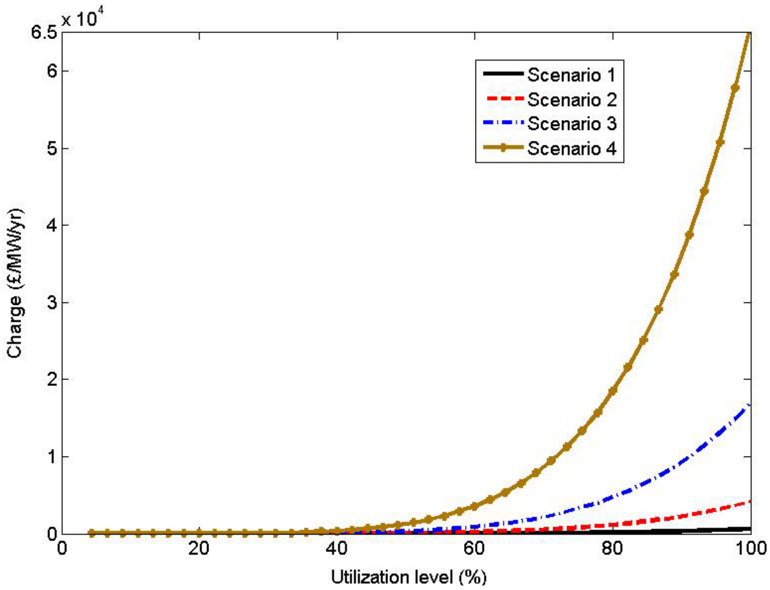

Figure 5-3 Charges for uninterruptible load under different scenarios

Charge comparison for uninterruptible loads in the foregoing mentioned four scenarios is demonstrated in Figure 5-3. The lines show the similar patterns as given in Figure 5-2. Charges increase exponentially with the increase in loading levels and the increasing proportion of uninterruptible load. Compared with the results from the original model in scenario 4, charges from the first three scenarios are fairly small.

Figure 5-4 carries out charge comparison for interruptible and uninterruptible loads in two scenarios: scenario 1: 40% interruptible load and 60% uninterruptible load, and scenario 2: 20% interruptible load and 80% uninterruptible load.

In both scenarios, charges for uninterruptible loads are constantly higher than those for interruptible loads at the same loading levels. One noticeable point is that charges for interruptible loads in scenario 2 are even higher than both two types of charges in scenario 1 at the same loading conditions, because that less circuits' capacity is available as much of the capacity is reserved for uninterruptible loads.

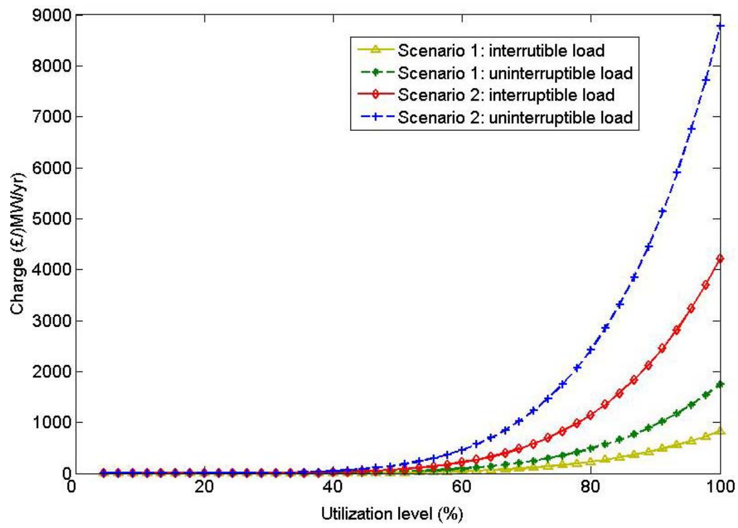

Figure 5-4 Charges comparison under two different scenarios

Based on this simple example, it can be said that the charging concept according to the division of load into interruptible and uninterruptible loads can effectively differentiate the security levels required by demand. Moreover, it can bring down charges dramatically in all loading conditions for both interruptible and uninterruptible loads, especially at higher levels. Further, the proposed model can effectively accommodate more interruptible loads compared with the original model when accommodating the same size of uninterruptible loads, the amount of which depends on the proportions of the two types of load.

5.5 Demonstration on a Practical Network

In this section, the proposed pricing model is demonstrated and compared with the original model on a practical grid supply point area taken from the UK network, given in Appendix. A. The network has three voltage levels, 66kV, 22kV, and 11kV, consisting of 11 circuits, 9 transformers, 6 loads and 1 generator.

The proportions of interruptible and uninterruptible loads are also assumed to be 20% and 80%. Circuit No.11 is not taken into consideration here as it is owned by the generator connected to busbar 1005. All branches' capacity is provided in Table 5-5.

Table 5-5 Capacity of all branches

Branch No.	Capacity (MVA)	Branch No.	Capacity (MVA)
L1	49.73	L12	28.75
L2	49.70	L13	28.75
L3	54.87	L14	40.00
L4	54.87	L15	40.00
L5	61.16	L16	31.25
L6	36.58	L17	31.25
L7	23.78	L18	40.00
L8	19.09	L19	40.00
L9	19.09	L20	28.75
L10	36.20	L21	28.75

5.5.1 Charge Evaluation

To assist analysis, Figure 5-5 depicts all branches' utilization levels. As seen, the most heavily loaded circuit is line No.4 linking bus 1008 and bus 1006. Circuit No.3 and transformers 12-17 also have relatively high loading levels.

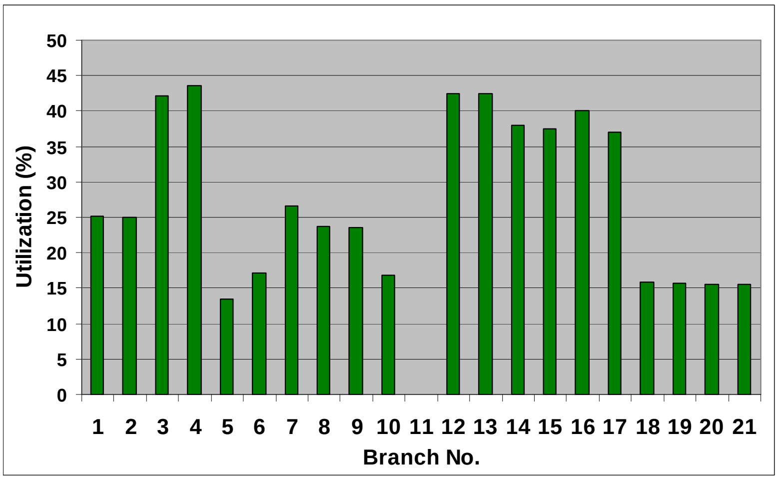

Figure 5-5 Branch utilization levels

In order to elaborate the impact from the interruptible and uninterruptible loads on network components, Figure 5-6 depicts the change in reinforcement horizons of the components supporting load at busbar 1003 caused by the injections connecting to them. As seen, L5 has the largest investment horizon, approximately 91yrs, and L3 and L4 have the smallest about 37yrs. The transposed "T" signifies how the connectees drag down the reinforcement horizons. As seen, for all components, an uninterruptible injection can even further bring down their horizons compared with an interruptible injection at the same busbar. The nearer new horizons tend to generate higher changes in components' annuitized present value of future reinforcement.

The computed charges for the two types of loads at all load busbars are provided in Table 5-6. Apparently, busbar 1003 has the biggest charges: 3.11£/kW/yr for the interruptible load and 6.361£/kW/yr for the uninterruptible load. It is because its supporting branches: No. 3-5 and 14-15, all are with relatively high loading levels. The smallest charges appear at busbar 1013, 0.19£/kW/yr for the interruptible load and 0.47£/kW/yr for the uninterruptible load, as their supporting branches are fairly lightly loaded.

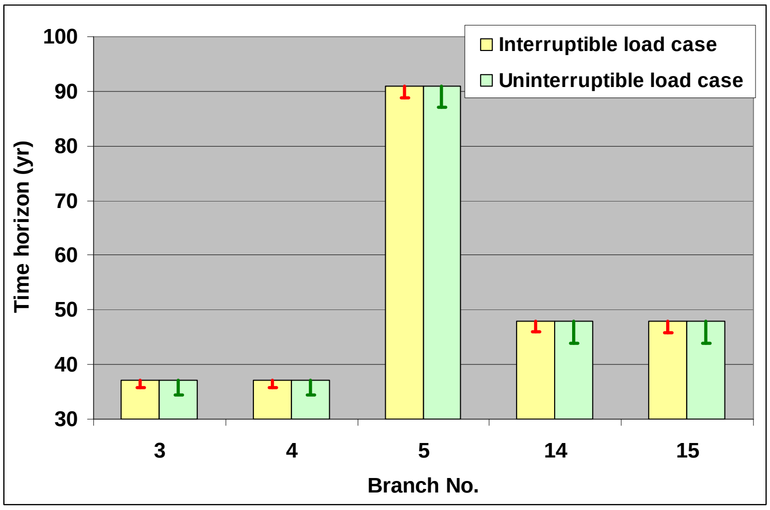

Figure 5-6 Time horizon comparison

Table 5-6 Charges from the proposed model (£/kW/yr)

Charge type	1001	1003	1006	1007	1009	1013
Interruptible	0.61	3.11	2.52	0.32	0.27	0.19
Uninterruptible	1.98	6.36	5.96	0.69	0.62	0.47

5.5.2 Comparison with the Original Model

This part thoroughly compares the proposed approach with the original model in terms of charges for interruptible and uninterruptible loads.

The original LRIC model reshapes components' maximum available capacity with their contingency factors, given in Table 5-7. Bigger contingency factor of a component means that more of its rated capacity should be reserved for contingencies, vice versa. As noticed, circuit No.5 has the maximum contingency factor of 3.77. Consequently, its maximum allowed capacity is axed from 61.16MVA, down to merely 16.21MVA. The maximum allowed capacity of all other branches is also brought down in proportion to their contingency factors.

Table 5-7 Contingency factor and maximum available capacity

No.	Contingency factor	Maximum allowed capacity (MVA)	No.	Contingency factor	Maximum allowed capacity (MVA)
L1	1.99	24.95	L12	2.05	14.04
L2	2.01	24.71	L13	2.05	14.04
L3	2.05	26.77	L14	2.04	19.59
L4	1.98	27.66	L15	2.07	19.33
L5	3.77	16.21	L16	1.94	16.08
L6	2.04	17.95	L17	2.11	14.78
L7	1.93	12.32	L18	2.00	19.97
L8	2.05	9.31	L19	2.04	19.65
L9	2.05	9.30	L20	2.02	14.21
L10	2.07	17.49	L21	2.03	14.19

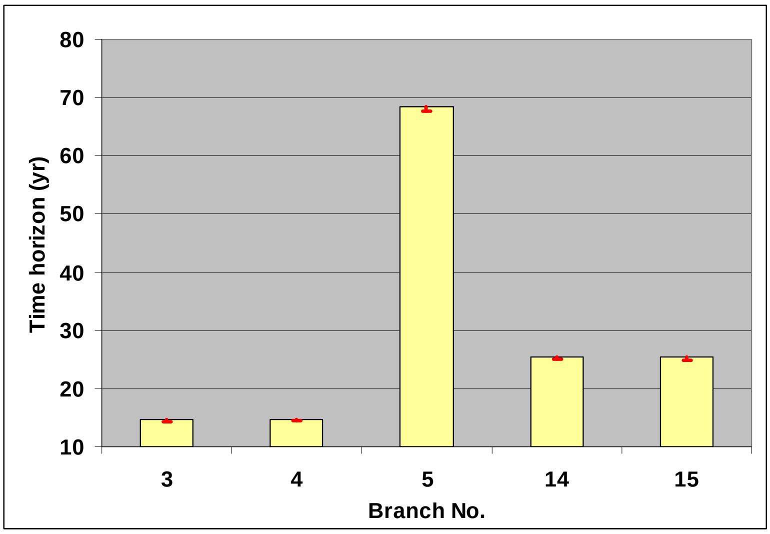

Figure 5-7 Investment horizons from the original model

Figure 5-7 depicts the investment horizons of the components supporting load at busbar 1003 evaluated with the original model with and without a nodal injection. Compared with the results demonstrated in Figure 5-6, all the original reinforcement horizons are here small. The biggest horizon is about 68yrs for No.5, which is approximately 91yrs in the new model; the horizons of L3 and L4 are merely 15yrs, which are 37yrs in the proposed model. The transposed "T" signifies that the horizons are slightly brought down, which are not obvious compared with results in Figure 5-6

The calculated charges from the original model are given in Table 5-8. Compared with the results given in Table 5-6, charges here are all greater at the same busbar. The highest is 19.44£/kW/yr at busbar 1003, which is approximately 3 times of the charge for uninterruptible loads and 6 times of the charge for interruptible loads at the same busbar. The lowest charge is 0.89£/kW/yr at busbar 1013, and it is also greater than charges at the same busbar given in Table 5-6.

Table 5-8 Charges from the original charging model (£/kW/yr)

Bus No.	1001	1003	1006	1007	1009	1013
Charge	3.87	19.44	17.43	1.68	1.53	0.89

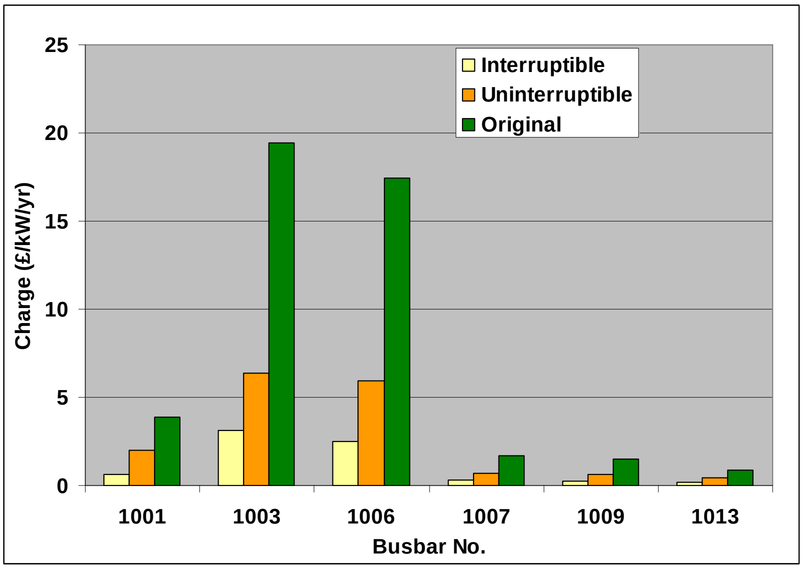

Figure 5-8 Charge comparison

Figure 5-8 graphically compares the nodal UoS charges provided in Tables 5-6 and 5-8. At all busbars, charges diversify from each other, depending on the locations in the network. At the same busbars, charges for interruptible loads are lower than those for uninterruptible loads, indicating the charges can differentiate and reflect their different security preference. On the other hand, charges for both of the loads are smaller than those from the original model at the same busbar. Further, the proposed approach can still produce charges that maintain the patterns of the original charges.

5.6 Chapter Summary

A novel charging methodology according to users' different security preference is proposed in this chapter. It works by dividing the load at each busbar into interruptible and uninterruptible parts and then prices them according to their impact on networks under both normal and contingency situations. Based on the extensive analysis, the following observations can be summarized:

- The new approach addresses the network work security issue in network pricing through close examining the impact from different types of users on network components under contingencies. It differentiates and respects users' security preference rather than deliver the same security levels for all. Charges are evaluated and levied on interruptible and uninterruptible loads based on their impact on investments under both normal and contingency circumstances.

- By dividing loads and pricing them differently, the overall network development cost in accommodating the same level of load growth is reduced, this had led to the marginal prices for either interruptible loads and uninterruptable loads are significantly smaller than those from the original model. Charges for interruptible loads are significantly lower compared with those for uninterruptible loads for they have less secure supply. The resultant locational cost-reflective charges can influence potential users' behaviors for the sake of system security. Users can also be financially rewarded if they choose lower security levels and thus reduce the otherwise needed network investment.

- This new approach provides a new economic tool to both DNOs and network users to encourage diversified security levels of supply, which can benefit both network utilities and their users. It should be pointed out that the proportions of interruptible and uninterruptible loads are crucial in this model. Although users can reduce their UoS charges by increasing their interruptible load, the risk of their supply lost might increase consequently. Therefore, in order to assist users to make the most beneficial decision, risk analysis should be carried out in the future to find the balance between network charges and the risk.

Chapter 6

Network Pricing For Customer Reliability

THIS chapter proposes a novel network pricing model for security of supply by incorporating nodal unreliability tolerance and components' reliability characteristics.

6.1 Introduction

The present planning standard in the UK requires that large users or user groups at distribution networks should be secured against N-1 or even higher level contingencies [14]. Meanwhile, it also mandates that customers' supply can be partially interrupted in contingencies for a period of time with a certain amount. This philosophy is not properly reflected by the original security-oriented LRIC charging model, as it assumes that all customers should be secured against N-1 or higher level contingencies without any load loss, no matter how serious these contingency could be and how often they could happen. Consequently, it might produce over tightened security levels, leading to excessive network expansion.

Considering the drawbacks of this worst-case oriented deterministic security criterion, some utilities have turn to probabilistic criteria, which include both the occurring probability and outcome of contingencies. Undoubtedly, they can well capture the stochastic features of power systems. A compromising approach to reflect security of supply probably is to combine the merits of the two criteria together by considering both the output and occurring probability of contingencies. That is the philosophy behind the proposed approach in this chapter.

In this chapter, a charging model for network security considering both nodal unreliability tolerance and contingency occurring probability is proposed. It examines the change in network ability to deliver power due to the connection of new customers under certain security levels. The combination nodal tolerable expected energy not supplied (EENS) and the occurring probability of contingencies is translated into nodal tolerable loss of load, which can be interrupted during contingencies. The impact of the tolerable loss of load is then recognized in assessing components' reinforcement horizon change. This approach is testified and compared with the original model on two networks under different scenarios, in which the impact of different reliability levels on network charges is also investigated.

6.2 Impact of Different Reliability Components

Provided that a node's allowed EENS is *EENS* and a failed component's mean time to repair (MTTR) and failure rate (FR) that would lead to a loss of load at the node are *MTTR* and *FR* respectively, thus the tolerable loss of load can be evaluated with

$$TLoL = \frac{EENS}{MTTR \cdot FR} \tag{6-1}$$

In the following part, the impact of components' reliability and nodal unreliability tolerance on components' investment horizons is investigated for three typical networks in two scenarios: with and without an injection.

6.2.1 Single-circuit Case Analysis

Figure 6-1 shows a simple two-busbar system supporting a single demand group of P_0 via a circuit L1.

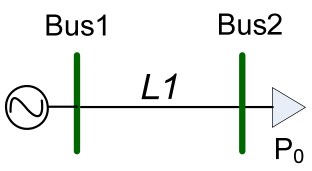

Figure 6-1 A two bus-bar test system

When L1 fails, the total demand at busbar 2 will be interrupted. Supposed that the tolerable EENS at busbar 2 is $EENS_0$, L1's future reinforcement horizon under a given load growth rate, r, can be assessed with

$$TLoL = \frac{EENS_0}{MTTR_1 \cdot FR_1} = P_0 \cdot (1+r)^n \tag{6-2}$$

where, $MTTR_1$ and FR_1 are L1's MTTR and FR.

Rearranging and taking logarithm of it produces

$$n = \frac{\log\left(\dfrac{EENS_0}{MTTR_1 \cdot FR_1}\right) - \log(P_0)}{\log(1+r)} \tag{6-3}$$

A tiny nodal increment connecting to bus 2 will bring forward L1's investment horizon. Suppose that the nodal reliability requirement does not change with the new injection, L1's new horizon can be identified by

$$\frac{EENS_0}{MTTR_1 \cdot FR_1} = (P_0 + \Delta P)\cdot(1+r)^{n_{new}} \tag{6-4}$$

Where, ΔP is the extra flow along L1 due to the injection.

Rearranging it gives

$$n_{new} = \frac{\log\left(\frac{EENS_0}{MTTR_1 \cdot FR_1}\right) - \log(P_0 + \Delta P)}{\log(1+r)} \tag{6-5}$$

6.2.2 Parallel-circuit Case Analysis

Figure 6-2 presents a demand group supported by two identical parallel circuits and the following analysis only focuses on L1. L1's future reinforcement is driven by the demand growth under L2's failure, as it has to accommodate the extra flow carried by L2 in normal conditions. It is assumed that L2's MTTR is $MTTR_2$, failure rate is FR_2 and rated capacity is RC_2, and the nodal tolerable EESN is $EENS_1$. L1's reinforcement horizon can be determined by assessing the impact of load growth on its spare capacity while L2 fails.

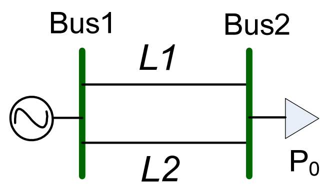

Figure 6-2 Two-circuit radial system framework

With the demand increasing, the surpassing part should be curtailed, if it exceeds L1's rated capacity. L1 can still support the demand group as long as the surpassing load part that needs be curtailed to resolve L1's overloading does not exceed the tolerance at busbar 2. Therefore, its investment horizon can be identified with

$$TLoL = \frac{EENS_0}{MTTR_2 \cdot FR_2} = P_0 \cdot (1+r)^n - RC \tag{6-6}$$

Taking logarithm of it produces

$$n = \frac{\log\left(\frac{EENS_0}{MTTR_2 \cdot FR_2} + RC\right) - \log(P_0)}{\log(1+r)} \tag{6-7}$$

When a new injection comes to busbar 2, L1's new investment horizon can be calculated by replacing P_0 in above formula with $(P_0 + \Delta P)$

$$n_{new} = \frac{\log\left(\frac{EENS_0}{MTTR_1 \cdot FR_1} + RC\right) - \log(P_0 + \Delta P)}{\log(1+r)} \tag{6-8}$$

Where, ΔP is the extra contingency flow along L1 triggered by the injection.

L2's reinforcement horizons can be calculated in the same way by examining the injection's impact on it when L1 fails.

6.2.3 Meshed Network Case Analysis

For a simple meshed network given in Figure 6-3, it is supposed that the failure of L1 can cause the maximum contingency flow along L2 and L3. It means that L2 and L3's future reinforcements are triggered by the demand increase when L1 fails.

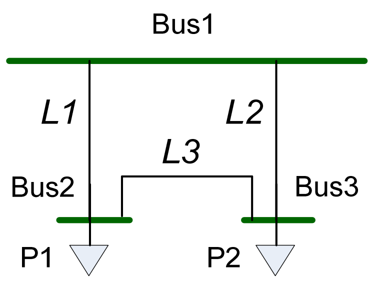

Figure 6-3 A simple meshed network

Suppose that the tolerable EENS at busbars 2 and 3 are $EENS_1$ and $EENS_2$ respectively, and the corresponding tolerable loss of load for P_1 and P_2 when L1 fails can be calculated with (6-1).

When L1 fails, L2 can still support P1 and P2 as long as the allowed curtailed load is within the tolerance and its reinforcement horizon can be identified with

$$TLoL_1 + TLoL_2 = \left(P_1 + P_2\right) \cdot \left(1 + r\right)^n - RC_2 \tag{6-9}$$

Where, $TLoL_1$ and $TLoL_2$ are the tolerable loss of load of P_1 and P_2.

Rearranging it gives

$$n = \frac{\log\left(\dfrac{EENS_1 + EENS_2}{MTTR_1 \cdot FR_1} + RC_2\right) - \log\left(P_1 + P_2\right)}{\log\left(1 + r\right)} \tag{6-10}$$

When an injection connects to either bus 2 or bus 3, L2's new investment horizon will change. Compared with the existing demand, the nodal injection is usually very small, so it is safe to assume that the circuit's future reinforcement is still triggered by the original contingency event, i.e. L1 fails. Thus, L2's new horizon will be

$$n_{new} = \frac{\log\left(\dfrac{EENS_1 + EENS_2}{MTTR_1 \cdot FR_1} + RC_2\right) - \log\left(P_1 + P_2 + \Delta P\right)}{\log\left(1 + r\right)} \tag{6-11}$$

where ΔP is L2's flow change due to the injection.

When L1 fails, L3's reinforcement horizon can be identified by taking the tolerable loss of load at busabr 2 into consideration,

$$TLoL_1 = P_1\left(1 + r\right)^n - RC_3 \tag{6-12}$$

Rearranging it gives

$$n = \frac{\log\left(\dfrac{EENS_1}{MTTR_1 \cdot FR_1} + RC_3\right) - \log\left(P_1\right)}{\log\left(1 + r\right)} \tag{6-13}$$

When a tiny injection comes to busbar 2, its new investment horizon changes to

$$n_{new} = \frac{\log\left(\frac{EENS_1}{MTTR_1 \cdot FR_1} + RC_3\right) - \log(P_1 + \Delta P)}{\log(1+r)} \tag{6-14}$$

where ΔP is its contingency flow change due to the injection.

L1's future reinforcement horizons are driven by the load growth under the failure of L2 and they can be obtained in the similar way.

It is worth pointing out that the tolerable curtailed power that a component can endure during its most serious contingency is the sum of all part of load that could be curtailed it supports. A component only needs to be reinforced when it can no longer support the total demand minus the curtailed part. Components' reinforcement horizons under contingencies are not only decided by their rated capacity and load growth rate, but also their maximum contingency flow and the tolerable loss of load they support, i.e. the nodal reliability level.

6.3 Reinforcement Horizon in Normal Case

Component's future reinforcement can be triggered by demand increase in either normal or contingency situations. Under normal context, its old horizon is

$$n = \frac{\log(RC) - \log(P_l)}{\log(1+r)} \tag{6-15}$$

where P_l is its normal case power flow.

Its new reinforcement horizon with an injection can be easily obtained by replacing P_l with (P_l+ΔP) in (6-15), given by

$$n_{new} = \frac{\log(RC) - \log(P_l + \Delta P)}{\log(1+r)} \tag{6-16}$$

where ΔP is the extra normal case flow along it due to the injection.

Obviously, components' normal case reinforcement horizons are only decided by their component's rated capacity, load growth rate, their loading levels and the additional normal case flow increment along them.

6.4 Charging Incorporating Reliability Standard

The core of this charging model is to determine components' reinforcement horizons under contingencies considering their reliability levels. It also follows the principle that a component needs to be reinforced if it can no longer support demand in normal conditions. By comparing the horizons from normal and contingency situations, the smaller one between the two is chosen to derive charges. The major implementation concept can be summarized as follows.

6.4.1 Components' Tolerable Loss of Load

Under N-1 or higher security level, all nodal tolerable loss of load can be easily determined using (6-1) when one circuit fails, decided by nodal tolerable EENS and the failed component's MTTR and FR. In order to determine how the tolerable loss of load would affect components' flow, sensitivity analysis can be adopted to directly relate nodal load to components' flow change [17]. Thus, their loading levels under all credible contingencies with all tolerable loss of load reduced from the original load can be calculated. Their actual contingency reinforcement horizons are calculated under their highest loading level cases.

It should be noted that although sensitivity analysis only provides approximate relationship between nodal demand and components' flow changes, it still can produce acceptable results. A more precise approach is to simulate how components' actual loading levels change with all tolerable loss of load curtailed under all contingences. But, such approach could be extremely time-consuming for big systems.

If more than one component fails at the same time, the MTTR and FR used to derive nodal tolerable loss of load should take all of these components into consideration. combined MTTR and FR can be determined respectively, the sizes of which depend on the failed circuits' characteristics, the contingencies' types, etc [31]. This is beyond the scope of this chapter and not discussed here.

6.4.2 Components' Original Horizons without Injections

All components' original normal case horizons are determined by running normal case power flow analysis, without considering any security criteria. Their original contingency case horizons are derived in their most serious contingencies with the tolerable loss of load considered. Components' actual original time horizons are selected as the smaller between the two.

6.4.3 Components' New Horizons with Injections

Components' new normal case horizons are calculated by running incremental flow analysis without considering security requirement with tiny power injections connected to the studied busbars. Their new contingency case horizons are assessed by running incremental contingency flow analysis to find their maximum loading levels, in which the nodal tolerable loss of load is curtailed from each busbar. They are then compared with the normal case new horizons and the smaller ones are chosen as actual new horizons.

6.4.4 Unit Price Assessment

Once all components' old and new reinforcement horizons are indentified, the unit price for each studied busbar can be assessed by implementing unit price evaluation.

The present value of future reinforcement of a component is

$$PV = \frac{Cost}{(1+d)^n} \tag{6-17}$$

where, d is the chosen discount rate and n is its investment horizon.

The change in its present value as a result of a nodal increment is

$$\Delta PV = Cost \cdot \left(\frac{1}{(1+d)^{n_{new}}} - \frac{1}{(1+d)^n} \right) \tag{6-18}$$

The incremental cost of the component is the annuitized change in its present value of future investment

$$\Delta IC = \Delta PV \cdot AnnuityFactor \tag{6-19}$$

The incremental price for a node is the accumulation of the present values of the incremental cost from all components supporting it

$$LRIC = \frac{\sum IC}{\Delta PI} \tag{6-20}$$

where, ΔPI is the injection at the node.

6.5 DC Load Flow Demonstration on a Small System

In this section, the new approach is demonstrated and compared with the original LRIC charging model on the simple network given in Figure 6-3 using DC load flow. D1 and D2 are chosen as 10 MW and 20MW respectively, each with a growth rate of 1.0%. In order to simplify analysis, the three circuits are assumed to be identical. Their capacity, cost, mean repair time, and failure rate are selected as 45MW, £1,596,700, 7.5hour/time and 0.5time/year respectively. So, their failure period is calculated as 3.75 hour/year. The allowed nodal loss of load under N-1 contingencies is supposed to 1MW within 3 hours for busbar 1 and 3MW within 3 hours for busbar 2, producing a tolerable EENS of 3MWh for bus 1 and 9MWh for bus 2.

6.5.1 Charge Evaluation

The three circuits' base states can be determined with load flow and contingency flow analysis, the results from which are provided in Table 6-1. As shown, the maximum contingency flows along L1 and L3 are caused by the failure of L2. L2's maximum contingency flow appears when L1 fails, which is the summation of P1 and P2, counted as 30MW.

Table 6-1 Results of the three-busbar system

Circuit No.	L1	L2	L3
Normal power flow (MW)	13.33	16.67	3.33
Maximum contingency power flow (MW)	30	30	20
Most serious contingency event	L2 out	L1 out	L2 out

Table 6-2 Horizons of the three circuits considering EENS tolerance (yr)

Injection location	L1	L2	L3
No injection	47.65	47.65	88.40
Bus 2	44.36	44.36	88.40
Bus 3	44.36	44.36	83.50

The contingency case horizons evaluation for the three circuits considers the tolerable loss of load from their supporting busbars. By comparing with their normal case horizons, it is found they have bigger contingency horizons in both cases with and without an injection, given in Table 6-2.

In the case without any injections, L1 and L2 have the same reinforcement horizons, 47.65yrs. An injection at busbar 2 or 3 also has the same effect on them, producing new investment horizon of 44.36yrs for them. Noticeably, an injection at busbar 2 does not affect L3's investment horizon, as it triggers not extra flow along L3 when L2 fails, whereas an injection at busbar 3 can bring L3' horizon down to 83.50yrs.

Table 6-3 Results of the three-busbar system (£/MW/yr)

	Cost from L1	Cost from L2	Cost from L3	Total charge
Bus 2	1211.17	1211.17	0.00	2422.34
Bus 3	1211.17	1211.17	125.70	2548.05

The derived costs from each circuit and the total nodal charges for the two load busbars are given in Table 6-3. The cost from L1 and L2 for demand at busbars 2 and 3 is the same, 1211.17£/MW/yr, as the injections cause the same effect on them. The cost from L3 is zero for demand at busbar 2, whereas it becomes to 125.70£/MW/yr for customers at busbar 3. The total nodal charge for each node is the summation of the cost from all their supporting circuits, which is 2422.34£/MW/yr at busbar 2 and 2548.05£/MW/yr at busbar 3.

6.5.2 Comparison with the Original Model

The original LRIC model reshapes the three circuits' maximum available capacity with their contingency factors down to 20MW, 25MW and 7.5MW respectively for catering for network contingencies. Their reinforcement horizons calculated with and without a nodal injection based on the reshaped capacity are outlined in Table 6-4.

Table 6-4 Reinforcement horizons of the three circuits without EENS (yr)

Injection location	L1	L2	L3
No injection	40.75	40.75	81.50
Bus 2	35.85	38.76	92.09
Bus 3	38.27	36.81	71.92

Compared with the results in Table 6-2, most of the horizons here are smaller, as the circuits' maximum available capacity is scaled down and the tolerable loss of load at each load busbar is not considered. One exception is for L3 when an injection is at busbar 2, whose investment horizon is deferred to 92.09yrs, as its normal case flow is reduced by the injection.

Table 6-5 Results of the three busbar system (£/MW/yr)

	Cost from L1	Cost from L2	Cost from L3	Total charge
Bus 2	3019.59	1108.24	-260.76	3867.07
Bus 3	1404.94	2347.28	460.41	4212.63

Table 6-5 provides the cost from each component for the two load busbars and the final charges. As seen, most of them are higher than those from the proposed approach due to their relatively high equivalent utilization levels. One exception is that an injection connects to busbar 2 can gain a reward of -260.76£kW/yr for using L3 rather than a cost. The reality is that the injection at busbar 2 has no impact on L3 in the contingency that drives L3's future reinforcement. Thus, it maintains L3's horizon as the same as the original one, leading to not reward at all. The proposed model, as demonstrated in the previous section, can capture the actuality, producing no cost from L3 for users at busbar 2.

The final charges are 3.67.07£/MW/yr for busbar 2 and 4212.63£/MW/yr for busbar 3, both of which are bigger than those from the proposed model. By taking nodal tolerable loss of load and circuits' reliability into consideration, the proposed method can dramatically reduce nodal charges.

6.6 Demonstration on a Practical Network

In order to further elaborate their difference, this section carries out the comparison of the two approaches on a practical grid supply point area taken from the UK network, depicted in Appendix. A. The discount rate and load growth rate are chosen as 1.0% and 6.9% respectively. All branches are supposed to have the same repair time of 4hour/time and failure rate of 0.5time/year, the combination of which lead to a failure period of 2 hour/year. For each component, as its MTTR and FR have the same effect on nodal tolerable loss of load depicted in (6-1), the following analysis only forces on the impact caused by its failure rate.

Table 6-6 outlines all load busbars' allowed loss of load and the tolerable EENS. Busbar 1001 has the smallest EENS of 3.5MWh, followed by other four busbars that have the same EENS. Busbar 1003's EENS is the biggest, 4.5MWh.

Table 6-6 Nodal reliability indices

Busbar	1001	1003	1006	1007	1009	1013
Allowed loss of load (MW)	7.0	9.0	2.0	8.0	2.0	2.0
Duration (hour)	0.5	0.5	2.0	0.5	2.0	2.0
EENS (MWh)	3.5	4.5	4.0	4.0	4.0	4.0

6.6.1 Low Utilization Level Analysis

In this part, calculations are carried out at system base loading level in three different scenarios, in which the network is assumed to be with different reliability levels:

- Scenario 1: use the base case nodal reliability levels given in Table 6-6;
- Scenario 2: increase nodal reliability levels by decreasing nodal allowed loss of load down to the half of the original values, thus causing nodal tolerable EENS and in turn the tolerable loss of load to be halved as well.
- Scenario 3: increase nodal reliability levels by decreasing assets' failure rates to the half of the original ones, causing the tolerable loss of load doubled.

Table 6-7 provides the calculated nodal charges from the three scenarios as well as those from the original model.

Table 6-7 Nodal charge comparison in four scenarios (£/kW/yr)

Busbar	1001	1003	1006	1007	1009	1013
Scenario 1: base case	4.08	20.22	16.66	1.46	0.18	0.91
Scenario 2: lower LoL	4.90	25.74	21.29	1.79	0.21	1.26
Scenario3: smaller FR	2.88	12.80	10.46	0.98	0.13	0.50
Original approach	5.59	32.59	26.80	2.14	0.24	1.71

Compared with scenarios 1 and 3, scenario 2 produces the highest charges for all 6 busbars. The reason behind is that that lower allowed loss of load means that less demand can be interrupted in contingencies and hence more of assets' spare capacity should be reserved to accommodate potential extra contingency flow. This, in turn, reduces assets' maximum available capacity. The highest charge is 25.74£/kW/yr at busbar 1003 and the lowest charge is at busbar 1009, 0.21£/kW/yr. Scenario 3 produces the lowest charges for all load busbars. It is because smaller assets' failure rates mean that they are less likely to fail, so less of their spare capacity needs to be reserved for catering for contingencies. By contrast, the original model generates the highest charges for all load busbars than those from the previous 3 scenarios and the highest charge also appears at busbar 1003, counted as 32.59£/kW/yr.

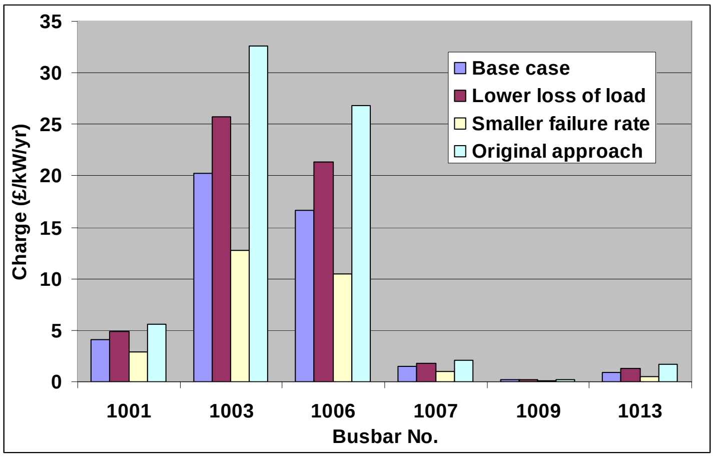

Figure 6-4 Charge comparison in lower loading condition

Figure 6.4 graphically compares the results in Table 6-7. As seen, charges from the proposed approach in all three scenarios maintain the charge pattern produced by the original model: charges produced by the original model are the highest, followed by charges from scenario 2, and charges from scenario 3 are the smallest.

6.6.2 High Utilization Level Analysis

In this part, the comparison is carried out in the same three scenarios but with higher components' utilization levels. The calculated results are given in Table 6-8.

Table 6-8 Nodal charge comparison (£/kW/yr)

Busbar	1001	1003	1006	1007	1009	1013
Scenario 1: base case	8.44	41.99	34.08	2.95	0.41	1.85
Scenario 2: lower loss of load	10.13	53.45	43.56	3.62	0.49	2.56
Scenario3: smaller failure rate	5.96	26.59	21.40	1.99	0.29	1.01
Original approach	11.53	67.70	54.95	4.28	0.52	3.49

Obviously, charges for all studied busbars grow dramatically in all four cases compared those in the previous part. Particularly, the highest charge rises to 67.70£/kW/yr at busbar 1003 from the original model, followed by 53.45£/kW/yr from scenario 3 at the same busbar. The high charges come out because all components' loading levels increase, which in turn greatly bring forward their future reinforcement horizons.

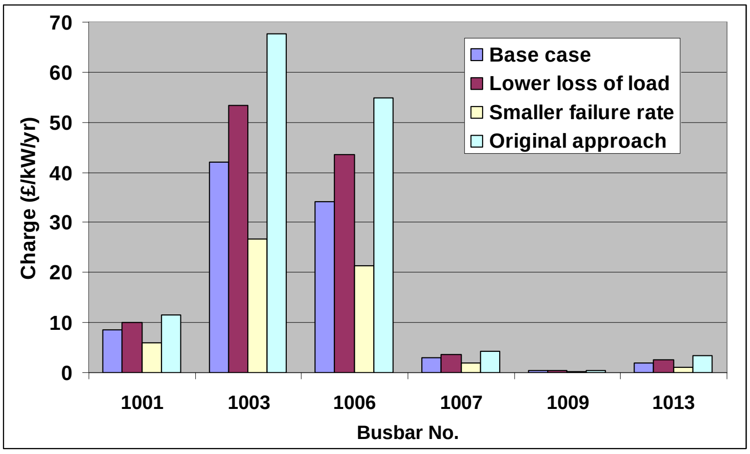

Figure 6-5 Charge comparison in higher loading condition

The graphical demonstration of the results by Figure 6-6 has a similar pattern depicted in Figure 6-5: charges from the original model are the biggest, followed by those in scenarios 2, 1 and 3.

6.6.3 Impact of Nodal unreliability and Asset Reliability Levels

In this part, the impact of nodal unreliability tolerance and assets' failure rates on nodal charges are investigated.

Figure 6-6 demonstrates the charge variation at busbar 1003 with respect to the decrease in its nodal unreliability tolerance, i.e. the allowed loss of load. The results from the proposed model are depicted with the solid line and those produced by the original model are represented by the dashed line. As seen, when the allowed loss of load is about 30% of the load at busbar 1003, charge from the new model is about 25.5£/kW/yr, which increases gradually with the decline in the tolerance. It reaches about 33.0£/kW/yr when the nodal allowed loss of load is zero. Charges from the original model, however, do not change with the variation in the tolerable loss of load at all, persisting at 32.59£/kW/yr.

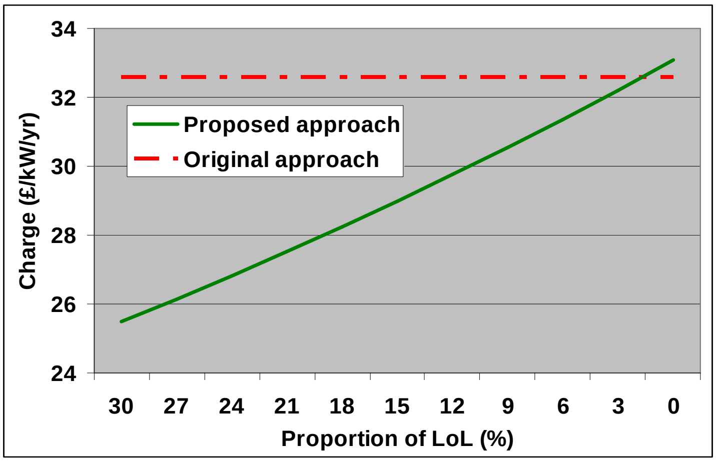

Figure 6-6 Charge variation with respect to the allowed loss of load

It should be noted that when the allowed loss of load is close to zero, the two lines cross at a point, and beyond it, charges from the proposed model exceed those from the original model. It is because the original model considers that an injection at 1003 can defer L5's investment horizon and therefore produce a negative cost for users at busbar 1003. By contrast, the proposed model produces no cost from L5 for users at the busbar. So, the total charges from the new model should be bigger than those produced by the old model when the allowed loss of load is zero.

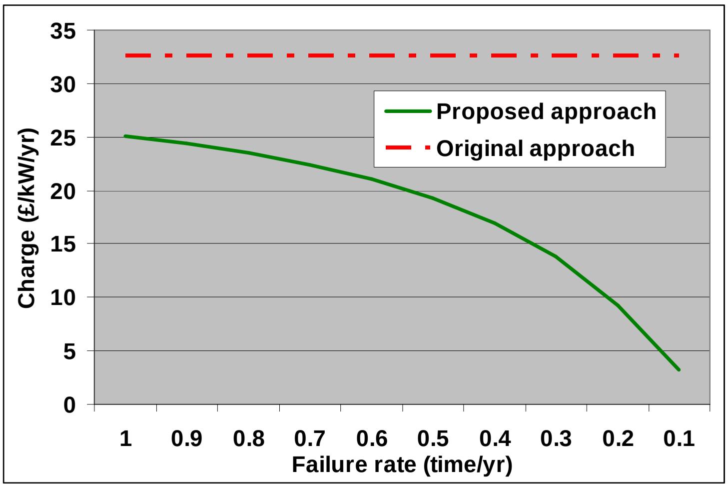

Figure 6-7 Charge variation with respect to failure rate

In Figure 6-7, the impact of components' reliability on the resultant charges at busbar 1003 is presented and compared with those from the original model. Obviously, the proposed model produces charges decreasing gradually with the decline in circuits' failure rate. When they are 1.0 time/yr, the computed charge is approximately 25£/kW/yr. It decreases steadily and reaches merely about 4£/kW/yr with a failure rate of 0.1time/yr. The reason is that when their failure rates are small, they rarely fail and hence, less of their capacity needs to be reserved for catering for contingencies.

In the extreme cases that all components' failure rates are zero, they do not fail at all and hence there is no difference between contingency cases and normal cases. In such situation, charges are evaluated by only considering how load growth would affect components' rated capacity, and there is no need to consider contingency flows and nodal allowed loss of load.

As observed in this example, nodal charges are brought down by considering the unreliability tolerance at each load busbar, the degree of which depends on nodal allowed loss of load and components' reliability level. More reliable components and less nodal reliability requirement tend to generate low charges, vice versa. Although both approaches of increasing components' reliability levels and reducing nodal unreliability tolerance can increase reliability level, the former seems more economical as it can produce even lower charges. But, improving component reliability is not an easy task and could be costly.

6.7 Chapter Summary

In order to address the issue of security of supply in network charging, a novel charging model is proposed by including nodal unreliability tolerance and components' reliability levels in assessing the impact of nodal injections on network components. Their impact is recognized by reflecting how they would affect components' ability to deliver energy in line with certain reliability levels. Based on the intensive analysis and the comparison with the original model on two test systems, the following observations can be reached:

- The original model deals with network security by reshaping components' rated capacity with contingency factors to reflect the maximum contingency flow they need to carry in contingencies. It is based on a deterministic criterion and assumes that those contingencies which cause components' maximum contingency flows definitely happen. The nodal tolerable unreliability level is not considered in it at all. The proposed model overcomes the disadvantages by taking both nodal unreliability tolerance and contingency occurring probability into account while evaluating injections' impact on components.

- The major factors influencing nodal reliability levels are the reliability levels of components and the allowed nodal loss of load amount and its duration, which together form EENS. They can significantly affect the nodal charges. More reliable components and bigger unreliability tolerance would lead to smaller charges, vice versa. The proposed approach can produce prolonged investment horizons, indicating that network components can be utilized for longer period so that potential reinforcement is deferred. Charges are consequently brought down especially when system loading level is high. The resultant charges can effectively reflect users' unreliability tolerance and components' reliability.

- Further, the charges from the new model still maintain the merits of the charges from the original model of being locational and cost-reflective, so that they can influence users' prospective behaviors. The only problem is that the new model would need great computational effort to analyze contingencies. But it should not impede its application as some time-efficient approximation approaches can be employed to spare computational burden.

Generally, this new model works well in accordance with network planning guides for network charging by taking nodal unreliability and components' reliability levels into consideration and can effectively reflect the practical planning philosophy.

Chapter 7

Conclusion

THIS chapter summarizes the thesis by outlining the major contributions and findings from the research. It also presents further work around the four main research areas.

Network charging models, as a measure to recover investment in networks from users, play a vital role in the deregulated and privatized environment. Due to the challenges brought forward by the stress on the increasing DGs and the uncertainties in demand and the promotion in efficiency, charging models therefore need to evolve to cope with them appropriately.

It is expected that network charging should not only be able to recover revenue allowed by the regulator, but also be cost-reflective so as to price users in accordance with the degree of their use-of-system. Cost-reflective pricing can produce forward-looking signals to influence their behavior and improve network efficiency. Network security, as a major drive for network investment, however, has not been well recognized in network charging models. Thus, this work has carried out intensive research in this area, proposed a number of new concepts on pricing security and implemented them on an existing LRIC charging model utilized in EHV distribution networks in the UK, extending the basic model to properly capture the nature of network planning. From the resultant charges, tariffs and impact analysis, the following conclusions can be drawn.

Network Pricing Using Marginal Approach

In order to assess the impact from a nodal injection on network components, the original LRIC model needs two runs of power flow analysis. Such technique is fairly easy to implement but extremely time-consuming especially for large scale systems, for which computational time might increase exponentially with the rise in busbar numbers. To improve the computational efficiency this model, a new LRMC charging model based on analytical approach is proposed, which can directly relate nodal power increments to changes in components' present value of future investment by using three partial derivatives.

- As demonstrated, the proposed LRMC can save significant computational time for large-scale networks by utilizing analytical approach, as it avoids running power flow analysis for every nodal injection. Despite this, it can produce similar results to those from the original LRIC model when the nodal injection for LRIC is small. The biggest difference appears when circuits are highly loaded and load growth rate is small.

- On the other hand, the LRIC model can examine the impact imposed on networks by any size injections by incorporating them into simulations. The proposed LRMC, however, can only accurately represent a very small injection.

- This work also examines the impact of the charges on the final revenue. As seen in the example, tariff difference is highly dependent on the difference in charges. Bigger charge difference tends to cause greater tariff difference. The work also demonstrates that the fixed adder approach is favored over the fixed multiplier approach as it can maintain the relativity of the pure economic signals. The fixed multiplier approach, as it scales up or down all charges to meet the target revenue, could amplify or reduce the relativities in the signals.

- The proposed LRMC is a good supplement to the original LRIC method not only because of its computational efficiency but also because of the additional insights from the interim results. It provides further insights into potential charge and tariff problems. The information, however, is hidden in the simulation based LRIC model.

Network Pricing Considering Security of Supply

In order to incorporate network security into pricing, the original LRIC approach works by reshaping components' maximum available capacity with a contingency factor to reflect the impact from contingencies. Charge evaluation for users is assessed on the basis of the new capacity. The effectiveness of this philosophy is limited as it can only reflect incremental impact on components under normal conditions, but not in contingencies. Hence, an enhanced model is proposed, considering the impact of nodal injections on components in both conditions.

- This new model evaluates users' impact on network components in contingencies through determining the change in components' investment horizon in contingencies due to a new user. Unlike the original model to resize components' maximum available capacity with contingency factors, this model thinks that part of network components' capacity should be reserved for catering for contingencies. Injections could also bring forward or defer assets' horizons under contingencies, not only in normal cases. It therefore chooses the smaller new horizons from the two situations to derive charges.

- As seen in the demonstrations, charges from this new approach are not always smaller than those from the original charging model. Three major factors: loading level, load growth rate, and injection size, can tremendously affect the difference in charges produced by the original and new approaches. Higher loading level, larger load growth rate and bigger injection sizes tend to enlarge the difference.

- The only downside with the proposed model is that it needs more computational time to evaluate connectees' impact on network components in contingencies, especially for large-scale systems and higher level of security. In order to save computational effort, sensitivity analysis is carried out to directly work out to what extent a tiny injection would affect network components under both normal and contingency conditions. This avoids running power flow and contingency flow analysis for each injection. It produces quite similar results as long as the injection size is small for the simulation approach.

Network Pricing to Meet Users' Security Preference

The old philosophy of network planning is to provide users at the same locations with the same level of security. This is how the original LRIC model is implemented. In reality, users might prefer different security levels to meet their own needs. Consequently, their impact on the same components could vary greatly and should be reflected in network charging. So, a security-oriented charging methodology is proposed to price users according to their security preference.

- The model first divides demand at each busbar into interruptible and uninterruptible parts and then evaluates their different impact on components in both normal and contingency situations. For each demand composition, the smaller horizons of every component are selected to derive charges for them. Thereby, there are two types of charges at each busbar: charges for interruptible load composition and charge for uninterruptible load composition.

- As demonstrated in the examples, charges for interruptible load composition are smaller compared with those for the uninterruptible composition at the same busbar, as uninterruptible one needs to be secured in contingencies when more spare capacity is required. Their cost for using the same components can also diversify.

- The network charges considering customer with different security preference still maintain the relative strength of locational charges from the original model, they are locational, cost-reflective and respect consumer choices. They thus can be utilized to guide potential users to the sites where sufficient spare capacity is available in normal and contingency situations respectively. Consequently, users can be encouraged to choose different security levels of supply as well in accordance with their own requirement.

Network Pricing for Reliability

The network security that is recognized in the original LRIC model is based on deterministic criterion. It determines the amount of components' spare capacity to cater for contingencies based on the worst case. It assumes that all demand at all busbars needs to be secured under any contingencies and these contingencies will happen in the investment horizon considered. Such a philosophy, however, does not comply with the actual planning concept which allows partial interruptible load under contingencies. Thus, a new model for pricing for network reliability is proposed, by considering both nodal unreliability tolerance and components reliability levels.

- In the model, nodal allowed loss of load, components' mean time to repair and failure rate are combined together to produce a new index: nodal tolerable loss of load, which can have enormous influence on components' maximum available capacity. Components' contingency horizons are evaluated by examining how nodal injections can influence the capacity in contingencies with the tolerable loss of load at their supporting busbars reduced. The smaller horizons from normal and contingency situations are adopted to derive charges.

- The proposed approach can produce significantly lower charges compared with the original model. The major factors influencing the final charges are components' reliability levels, decided by their mean time to repair and failure rate, and the nodal tolerable loss of load and the duration. Users supported by more reliable components have smaller charges, but if they prefer less allowed loss of load, their charges tend to shoot up.

- The charges can effectively reflect users' and network components' reliability levels. They can be utilized to encourage users to have different reliability levels with different measures rather than to demand the same reliability levels. Further, the examples also show that components' reinforcement horizons are deferred. It means that they can be utilized for a longer period so that potential reinforcement can be postponed. This will translated into lower use of system charges for network users.

Chapter 8

Future Work

THIS chapter presents future works that can be done to improve LRIC charging methodology as well as its interaction with other considerations in network planning.

Pricing for Reliability with Customers' Interaction

Under the competitive environment, users might prefer different reliability levels due to economic or social concerns. By adopting interruptible and uninterruptible scheme, they are granted with the freedom to choose the reliability levels they prefer. In implementing this scheme, the proportion between interruptible and uninterruptible loads becomes a vital issue as different proportion can lead to quite diversified UoS charges as well as value from loss of load. The impact of different proportions varies for customers in different sectors, such as industrial, commercial and residential; they will have profound impact on the system development.

Further, users' reliability levels not only depend on the operation strategies adopted by network operator to deal with the alert and contingency situations, such as load shedding or load shifting, but also on components' reliability levels, which depend on their own characteristics and other factors, such as performance of staff, locations, weather, etc. A reliability-oriented charging model should not only reflect the reliability systems supply but also respect the reliability levels that users choose. They can opt to different load shedding schemes so as to be encouraged to interact with networks. Risk-benefit analysis for end users should be further carried out to find the right balance between network UoS charges and value from lost load.

Interaction between Long-run and Short-run Pricing

It should be noted that locational charges set by either LRIC or LRMC are to recover the network fixed costs. This is of paramount importance to DNOs at the moment when they are expecting to connect substantial amount of DGs. Efficient locational messages will incentivise the prospective DGs to connect to appropriate sites so as to minimise the network development costs.

The long-run marginal and incremental cost pricing models provide locational messages to minimise the network development costs. The long-run and short-run pricing should be complementary and interactive. Efficient long-run messages should encourage prospective network customers to better utilize the existing network, thus reducing congestion and losses in the long run. The short-run locational marginal pricing aims to minimize congestion and loss in order to improve the efficiency of the existing network and delay the needed network upgrades. Network operators should strike the right balance between network investment cost and congestion and losses cost, which should be reflected in the interaction between the two pricing schemes.

Load Growth rate, Inflation Rate and Discount Rate

Work to date of LRIC model assumes that the cost of network reinforcement does not change over time, i.e. the cost of purchasing a piece of network equipment in the future is the same as it is today. The charging model as it stands today does not account for the potential price increase in network components or its decline in purchasing power of currency caused by economic inflation. In reality, however, the price of goods continuously increases in the long run due to varying factors such as price increase of resources, man power, technologies, etc, which comes into the form of inflation rate. Therefore, there is a degree of inflation existing in the economy reflecting the rise in the general level of prices of goods and services. This inflation in economy should be reflected in the present value of the future reinforcement in LRIC pricing.

On the other hand, future load growth in the LRIC model is derived from load prediction for a period of time and then annuitized whereas discount rate is decided by Ofgem based on interest rate and rate of return for DNOs. The selection of inflation rate, discount rate and load growth rate are very important to the end results of LRIC pricing and the original model assumes they are independent of each other. In reality, they are interdependent and intertwined. A change in one factor will affect the other two and over time it will feed back to itself. The underlying relationships between the three parameters therefore should be justified by companies who put forward their projected load growth and network investment.

Pricing Considering More Influencing Factors

Presently, the LRIC charging model only takes thermal limit into consideration to decide the investment horizon of a component, disregarding the impact of other influencing factors. The work that has been done in this thesis still only focuses on the thermal and reliability constraints.

It is know the future network investment should be able to reflect the reality in power systems and their true drivers. As noted in the previously considered large volume of references, voltage stability, fault current, network dynamic stability, etc, can also drive network future reinforcement. The LRIC model therefore should take them into consideration during the procedure of assessing the impact from users on the existing network components. By using available transfer capacity to measure the true impact from network users, charging models can therefore identify the actual investment horizon of their supporting components, and thereafter to derive charges.

Pricing to Accommodate Increasing Renewables

With the vast volume of renewable generation connected to networks especially wind power, their impact on networks is enormous. Due to the stochastic nature of their resources, the intermittent generation imposes great difficulty on network planning, such as the selection of circuit's capacity. In this context, network capacity can be a bottleneck for the connection of increasing renewable capacity. Although this issue can be easily solved by ensuring enough investment in networks, it could be a waste of money to build excessive circuits.

Network charging models need to recognize the intermittent characteristics of renewables and project their impact into circuits' capacity. These renewables could drive future reinforcement quite differently compared with traditional fossil-fired generation as their outputs vary with the availability of the resources, such as wind solar power, etc, which in turn is decided by time, weather, etc. Therefore, the reasonable expansion in network capacity is vital for renewable connection and should be reflected in network charging. On the other hand, charging models should also be able to produce charges levied on renewable generation which are not only cost-reflective, but also able to take account of their prospective behaviors.

Appendix. A

A.1 Network Configuration

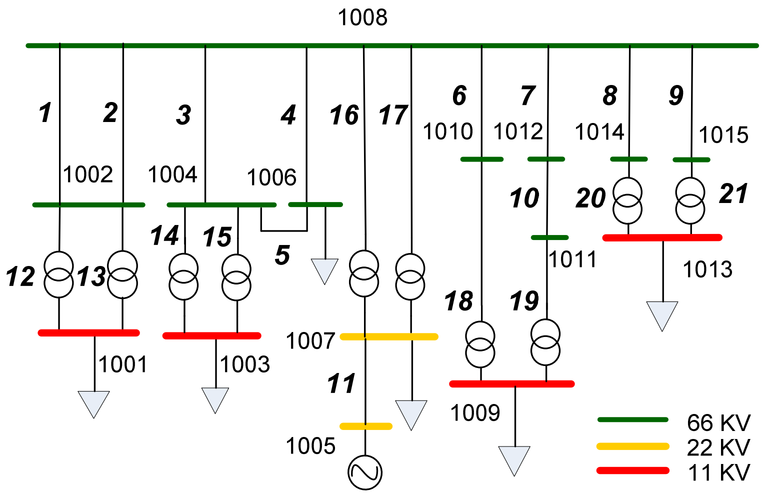

Figure. Appendix-1 An actual grid supply point area test system

A.2 Typical Asset Cost

Note: due to confidential reason, the detailed date of the test system cannot be provided, but a list of typical asset cost is given in Table Appendix-1.

Table. Appendix-1 Unit Costs for Modelled Asset Replacement [89]

Asset	Units	IP	FP	PB Power	IP - FP (%)
Services					
OHL - Service Replacement	#	0.40	0.40	0.70	0.0%
OHL - Cut-out Replacement	#	0.15	0.20	-	32.8%
UG - Service Replacement	#	1.00	1.01	0.93	1.3%
UG - Cut-out Replacement	#	0.16	0.16	-	4.7%
Cables					
LV Main (UG Plastic)	km	77.9	98.4	80.7	26.4%
6.6/11kV UG Cable	km	89.5	82.9	82.3	-7.4%
20kV UG Cable	km	89.5	82.9	167.9	-7.4%
HV Sub Cable	km	300.0	300.0	210.1	0.0%
33kV UG Cable	km	264.9	256.8	253.4	-3.1%
66kV UG Cable	km	300.0	300.0	455.4	0.0%
EHV Sub Cable	km	300.0	300.0	608.4	0.0%
132kV UG Cable	km	1091.9	1047.1	1031.0	-4.1%
132 kV Sub Cable	km	2167.0	1966.7	1216.8	-9.2%
Transformers					
6.6/11 kV Transformer (PM)	#	3.4	2.9	4.2	-15.1%
6.6/11 kV Transformer (GM)	#	14.0	13.2	13.3	-5.5%
20 kV Transformer (PM)	#	3.7	0.5	6.5	-86.4%
20 kV Transformer (GM)	#	12.3	14.4	16.4	17.1%
33 kV Transformer (PM)	#	5.8	7.9	5.8	36.0%
33 kV Transformer (GM)	#	399.8	377.9	519.6	-5.5%
66 kV Transformer	#	455.5	440.2	616.7	-3.4%
132 kV Transformer	#	1077.9	1018.7	1200.7	-5.5%
Switchgear					
LV Pillar (ID)	#	6.4	6.4	7.5	0.0%
LV Pillar (OD)	#	6.8	6.8	6.6	0.0%
LV Board (WM)	#	8.4	8.4	10.6	0.0%
6.6/11 kV CB (PM)	#	8.4	8.2	11.0	-2.6%
6.6/11 kV CB (GM) - Primary	#	58.7	51.8	31.8	-11.7%
6.6/11 kV CB (GM) - Secondary	#	11.7	11.2	10.4	-3.9%
6.6/11 kV Switch (PM)	#	4.1	2.5	7.5	-39.0%
6.6/11 kV Switch (GM)	#	8.2	7.0	8.9	-14.3%
6.6/11 kV RMU	#	12.0	13.0	13.8	8.0%
20 kV CB (PM)	#	8.4	8.0	13.8	-5.0%
20 kV CB (GM)	#	12.2	12.0	64.4	-1.4%
20 kV RMU	#	12.9	14.5	16.4	12.5%
33 KV CB (ID)	#	110.0	109.0	85.5	-0.9%
33 kV CB (OD)	#	83.7	50.1	60.2	-40.1%
33 kV RMU	#	259.5	259.5	31.8	0.0%
66 KV CB (ID & OD)	#	313.4	316.3	382.1	0.9%
132 kV CB (ID & OD)	#	692.8	679.6	694.0	-1.9%
Overhead Lines - Reconductoring					
33kV Tower Line	km	39.1	39.0	-	-0.3%
66kV Tower Line	km	68.4	53.4	-	-21.9%
132 kV Pole Line	km	52.9	52.9	-	0.0%
132 kV Tower Line	km	65.0	82.1	-	26.3%
Support - Replacement					
33kV Tower	#	35.8	39.2	0.0	9.4%
66kV Tower	#	68.4	65.0	88.6	-5.0%
132 kV Pole	#	2.6	2.6	7.7	0.0%
132 kV Tower	#	108.9	108.9	108.9	0.0%
Refurbishment and Fittings					
132 kV Tower Refurbishment	#	5.0	N/A	0.0	N/A
132 kV Fittings	#	4.5	4.5	5.1	0.0%

Appendix. B

Present value: is the value on a given date of a future payment or series of future payments, discounted to reflect the time value of money and other factors such as investment risk [90].

Allowed revenue: is the sum of the base rate returns and the operation and maintenance (O&M) costs. The base rate is determined based on a bottom-up approach where all the assets are evaluated using the acquisition value minus the depreciation. The O&M costs are also set by the regulator, which is based on the model adjusted to the distribution company profile [89, 91].

Rate of return: in finance, rate of return (ROR), also known as return on investment (ROI), rate of profit or sometimes just return, is the ratio of money gained or lost (whether realized or unrealized) on an investment relative to the amount of money invested [92].

Yardstick: is utilized to reflect the investment costs of accommodating extra 500MW in DRM model, which also means the benchmark of costs at different voltage or transformation levels. The annuitized yardstick over expected useful lives at an appropriate cost of capital is [93]

$$Yardstick = \frac{\sum (500MW\ Model \times Unit\ Cost)}{Diversity\ Factor} \times Annuity\ Factor \qquad \text{(Appendix.1)}$$

More details of DRM model can be found in [93]

Annuity factor: is used in finance theory to refer to any terminating stream of fixed payments over a specified period of time. This usage is most commonly seen in discussions of finance, usually in connection with the valuation of the stream of payments, taking into account time value of money concepts such as interest rate and future value [94].

Appendix. C

C.1 Matlab-based Code of LRIC model

Note: due to confidential reason, the detailed code of the LRIC model cannot be provided, but the simple Matlab-based LRIC code is provided in this part.

```
%------------------------------------------------------------
%------------------------Code Starts-----------------------
%------------------------------------------------------------

format long;

C=45;
p=1;
d=0.069;
asset=3193400;
annuity_factor=0.0741+0.009;
r=0.01;
D=5:1:45;

n=(log10(C)-log10(D))./log10(1+r);
PV=asset./(1+d).^n;

n_new=(log10(C)-log10(D+p))./log10(1+r);
PV_new=asset./(1+d).^n_new;
%--------simulation resutls----------
delta_u = ((PV_new-PV).*annuity_factor)./p
plot(D/C,delta_u,'black','LineWidth',2);
hold on;

% %---------analytical results-------
delta_u_analytical=(asset./C).*(log10(1+d)./log10(1+r)).*((D/C).^(log
10(1+d)./log10(1+r)-1));
delta_u_analytical= delta_u_analytical .* annuity_factor./p

% %-------------------------------------------------------------
% %-------------the following is for fixed adder and multiplier-----
% %--------------------------------------------------------------
% %-----------for simulation--------
adder=(allowed_revenue - (delta_u.*D+delta_u2.*D2))./(D+D2);
adder_charge=adder+delta_u; %adder charge of line1
adder_charge2=adder+delta_u2; %adder charge of line2
multiplier=(allowed_revenue./(delta_u.*D+delta_u2.*D2))-1;
multiplier_charge=delta_u.*(1+multiplier);%multiplier charge of line1
multiplier_charge2=delta_u2.*(1+multiplier);%multiplier charge of
line2
%----------for analytical---------
adder_analytical=(allowed_revenue -
(delta_u_analytical.*D+delta_u_analytical2.*D2))./(D+D2);
adder_analytical_charge=delta_u_analytical+adder_analytical;
%adder charge of line1
```

```
adder_analytical_charge2=delta_u_analytical2+adder_analytical;
%adder charge of line2
multiplier_analytical=(allowed_revenue./(delta_u_analytical.*D+delta_
u_analytical2.*D2))-1;
multiplier_analytical_charge=delta_u_analytical.*(1+multiplier_analyt
ical);%multiplier charge of line1
multiplier_analytical_charge2=delta_u_analytical2.*(1+multiplier_anal
ytical);%multiplier charge of line2

plot(D/C,adder_charge,'black','LineWidth',2);
hold on;
plot(D/C,adder_analytical_charge,'red','LineWidth',2);
hold on;
plot(D/C,adder_charge2,'blue','LineWidth',2);
hold on;
plot(D/C,adder_analytical_charge2,'green','LineWidth',2);
hold on;
plot(D/C,multiplier_charge,'black','LineWidth',2);
hold on;
plot(D/C,multiplier_analytical_charge,'red','LineWidth',2);
hold on;
plot(D/C,multiplier_charge2,'blue','LineWidth',2);
hold on;
plot(D/C,multiplier_analytical_charge2,'green','LineWidth',2);
hold on;

% %-------the following is for 3-D figure--------------------------
clear;
C=45;
p=1;
d=0.069;
asset=3193400;
annuity_factor= 10/3;
r=0.0050:0.001:0.045;
D=5:1:45;
allowed_revenue=asset*annuity_factor;
[r,D]=meshgrid(r,D);
n=(log10(C)-log10(D))./log10(1+r);
PV=asset./(1+d).^n;
U=PV/C;

n_new=(log10(C)-log10(D+p))./log10(1+r);
PV_new=asset./(1+d).^n_new;
U_new=PV_new./C;
delta_u = ((U_new-U).*annuity_factor)/p;
adder=(allowed_revenue - delta_u.*D)./D;
multiplier=(allowed_revenue./(delta_u.*D))-1;
%---------the following is for analytical analysis
delta_u_analytical=(asset./C).*(log10(1+d)./log10(1+r)).*((D/C).^(log
10(1+d)./log10(1+r)-1));
delta_u_analytical= delta_u_analytical .* annuity_factor./C ;
adder_analytical=(allowed_revenue - delta_u_analytical.*D)./D;
multiplier_analytical=(allowed_revenue./(delta_u_analytical.*D))-1;

colormap hsv;
surfc(r,D/C,multiplier-multiplier_analytical);
%-------------------------------------------------------------
%-------------------------Code Ends------------------------
%-------------------------------------------------------------
```

Publications

C. Gu and F. Li, “Long-Run Marginal Cost Pricing Based on Analytical Method for Revenue Reconciliation”, *IEEE Transactions on Power Systems*, 2010 (accepted and ready to appear, No.: TPWRS2047278)

C. Gu, F. Li, and L. Gu, “Application of long-run network charging to large-scale systems”, *7th International Conference on the European Energy Market (EEM),* 2010, Page(s): 1- 5

C. Gu and F. Li, “Long-run incremental cost pricing considering uncertain future load growth”, *IEEE Power & Energy Society General Meeting,* 2009. PES '09.

C. Gu and F. Li, “Sensitivity analysis of long-run incremental charge based on analytical approach”, *20th International Conference and Exhibition on, CIRED 2009.*

Long-run Marginal Cost Pricing Based on Analytical Method for Revenue Reconciliation

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Abstract-- **Incremental and marginal approaches are two different types of methods to price the use of networks. The major difference between them is in the way they evaluate the costs imposed by network users. The former calculates network charges through simulation and the latter derives charges with a sensitivity-based analytical approach. Both charging models aim to send cost-reflective economic signals to customers, providing an economic climate for the cost-effective development of networks.**

In this paper, a novel long-run marginal cost (LRMC) pricing methodology based on analytical method is proposed to reflect the impacts on the long-run costs imposed by a nodal injection through sensitivity analysis. The sensitivity analysis consists of three partial differentiations: i) the sensitivity of circuit power flow with respect to nodal power increment, ii) the sensitivity of the time to reinforce network with respect to changes in circuit power flows, and iii) the sensitivity of present value of future reinforcement with respect to changes in time to reinforce. Two test systems are employed to illustrate the principles and implementation of the proposed method. Results from incremental and marginal approaches under different system conditions are compared and contrasted in terms of charges and tariffs. The proposed method, as demonstrated in the test systems, can produce forward-looking charges that reflect the extent of network utilization levels in addition to the distance that power must travel from points of generation to points of consumption. Furthermore, the proposed method is able to provide further insights into factors influencing network charges.

Index Terms-- **Long-run marginal cost, Long-run incremental cost, Network charging, Load growth rate**

I. Introduction

NETWORK charges are charges against network users for their use of a network. Methodologies used for setting network charges need to recover the costs of capital, operation and maintenance of a network and provide forward-looking, economically efficient messages for both consumers and generators [1, 2]. In order to achieve these objectives, it is essential that network charges can reflect the costs/benefits that new network users impose on networks. It is for this reason that the concept of incremental/marginal charging methodologies is introduced to reflect the costs of network operation and development incurred by new generation and load connection [1, 3, 4].

Developing a long-run pricing model has been viewed as a formidable task. Previously proposed methodologies fall into two categories: long-run incremental cost pricing and long-run marginal cost pricing [1, 5-7]. The biggest difference between them is in the way they evaluate the effects on the long-term network development costs from a nodal injection. The long-run incremental charge for a nodal is evaluated by comparing the present value of future reinforcement with and without the nodal injection. This type of charging methodology is fairly easy to implement but takes long computational time for a large- system. On the other hand, marginal methods use analytical equations to evaluate the impact of nodal injection on long-run network development costs [1, 8]. This type of methodology is computationally efficient but based on the assumption that the relationship resulted from a small injection/withdrawal can be extrapolated to large injection/withdrawal. Inaccuracies will be resulted in as the relationship between the nodal injection and the network development costs is highly non-linear.

There are some papers focusing on the difference and relationship between the two type pricing [8, 9] and the use of these charging methods in real networks [10-13]. However, most of them require a least-cost network planning to determine the changes in network development costs from nodal generation/demand increment; but the knowledge of the future generation/demand is far from certain. Furthermore, these methods passively react to a set of projected future generation/demand patterns, not able to provide financial incentives to guide new network users to appropriate locations that lead to the least network development costs[14].

The first method that directly links long-term network development costs with nodal increment was presented by Li and Tolley [15]. The proposed long-run incremental cost (LRIC) pricing makes use of the un-used capacity of an exiting network to reflect the costs of advancing or deferring future investment consequent upon the addition of generation or load at each study node. For LRIC charges for each node, two load flow runs are required to assess if the nodal increment brings forward or defers the future reinforcement. Such simulation approach is easy to implement and can provide forward-looking signals to reflect the extent of the use of the network by a new connectee. The shortcoming is that the simulation approach takes much longer time to calculate charges for large systems, as the computational time rises exponentially with the increasing size of systems. Further, it can be difficult to detect implementation errors with the simulation approach.

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In this paper, a novel long-run marginal cost (LRMC) charging method is proposed following the same principle of [15], but utilizing sensitivity analysis to significantly reduce the computational burden for large systems. In the proposed LRMC approach, the change of present value of future reinforcement with respect to a nodal power increment is represented by three partial differentiations: i) sensitivity of circuit loading level with regard to nodal injection, ii) sensitivity of time to reinforce with respect to circuit loading level, and iii) sensitivity of the present value of future reinforcement with respect to time to reinforce. Using the sensitivity approach, LRMC calculates charges that can reflect very small changes in nodal generation/demand accurately compared with LRIC model. In practice, however, the nodal increment can be large, and therefore LRMC might introduce inaccuracy for larger increment compared with the LRIC approach, as the latter can accurately simulate the change in network loading conditions incurred by a large nodal increment. Two test systems are employed to compare the proposed LRMC approach with LRIC method under different load growth rates (LGRs), different loading levels and with different sizes of injections for LRIC. The comparison shows the boundary conditions in which the two methods conform well, and in which the two depart and LRMC is no longer appropriate to be applied. Further, in order to compare the economical signals provided by the two charging models to network users, tariffs reconciled from the LRIC and LRMC charges with two reconciliation methods are also discussed.

The rest of the paper is organized as follows: section II gives a brief introduction to LRIC charging approach. In section III, the novel LRMC charging method is presented. Section IV introduces two commonly used scaling methods for revenue reconciliation. Section V provides two test systems to compare the results derived from LRIC and LRMC. Section VI provides some discussions concerning the proposed method. Finally, some conclusions are drawn in section VII.

II. Long-Run Incremental Cost Pricing Model

In the original LRIC pricing model [15], for components in network that are affected by a nodal injection, there will be a cost associated for it if the investment is accelerated or a credit if it is deferred. The LRIC model has the following three implementation steps.

A. Present Value of Future Investment

If a circuit l has a maximum allowed power flow of C_l, supporting a power flow of P_l, the number of years it takes P_l to grow to C_l under a given LGR, r, can be determined with

$$C_l = P_l \cdot (1+r)^{n_l} \tag{1}$$

Where, n_l is the number of years taking P_l to reach C_l.

Rearranging (1) and taking the logarithm of it gives

$$n_l = \frac{\log C_l - \log P_l}{\log(1+r)} \tag{2}$$

Assume that investment will occur in year n_l when the circuit utilization reaches C_l and with a chosen discount rate of d, the present value of future investment is

$$PV_l = \frac{Asset_l}{(1+d)^{n_l}} \tag{3}$$

Where, $Asset_l$ is the modern equivalent asset cost.

B. Cost Associated with Power Increment

If power flow change along line l is ΔP_l as a result of a nodal injection, the time to future reinforcement will change from year n_l to year n_{lnew}, defined by

$$C_l = (P_l + \Delta P_l) \cdot (1+r)^{n_{lnew}} \tag{4}$$

Equation (4) gives the new investment horizon n_{lnew}

$$n_{lnew} = \frac{\log C_l - \log(P_l + \Delta P_l)}{\log(1+r)} \tag{5}$$

The new present value of future reinforcement becomes,

$$PV_{lnew} = \frac{Asset_l}{(1+d)^{n_{lnew}}} \tag{6}$$

The change in present value as a result of the injection is given by

$$g(r) = \Delta PV_l = Asset_l \cdot \left(\frac{1}{(1+d)^{n_{lnew}}} - \frac{1}{(1+d)^{n_l}} \right) \tag{7}$$

The incremental cost for circuit l is the annuitized change in present value of future investment over its life span,

$$\Delta IC_l = \Delta PV_l \cdot AnnuityFactor \tag{8}$$

C. Long-run Incremental Cost

The nodal LRIC charge is the summation of incremental cost over all circuits supporting it, given by

$$LRIC_i = \frac{\sum_l \Delta IC_l}{\Delta PI_i} \tag{9}$$

Where, ΔPI_i is the size of power injection at node i, and here we assign it to be 1MW.

In practice, all networks are designed to withstand credible contingencies, but this comes at a significant cost to network development. For the LRIC pricing model, it is important to recognise the level of spare capacity that is reserved for catering N-1 contingency. This can be determined by conducting a full N-1 contingency analysis. For each circuit, the base power flow and the maximum contingency flow are determined from base power flow and contingency analysis. Here, contingency factor is defined as the ratio of the maximum contingency flow over the circuit's base flow [16]. The maximum allowed power flow each circuit can carry considering N-1 contingency is

$$C_l = \frac{Rated\ Capacity_l}{Contingency\ Factor_l} \tag{10}$$

III. Long-Run Marginal Cost Pricing Model

The core of the LRIC method is to reflect: i) how a nodal injection might affect the level of spare capacity of network assets that support this injection, ii) how the change in spare capacity would influence the time to reinforce these assets, iii) how the change in time to reinforce can impact the present value of future reinforcement of these assets. These impacts can be approximated through three-step partial differentiations, which form the core of LRMC, given as

$$\frac{\partial PV_l}{\partial PI_n} = \frac{\partial PV_l}{\partial n_l} \cdot \frac{\partial n_l}{\partial P_l} \cdot \frac{\partial P_l}{\partial PI_n} \tag{11}$$

Where, P_l is the power flow along circuit l linking nodes i and j, n_l is the time to reinforce circuit l and PV_l is the present value of future reinforcement cost for circuit l.

Mathematically, the LRMC pricing can be implemented through the following steps.

A. Sensitivity of Circuit Power Flow to Nodal Injection

Equation (12) represents active power flow along a circuit from bus i to bus j.

$$P_{ij} = V_i^2 G_{ij} - V_i V_j (G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}) \tag{12}$$

If there is a small injection PI_n at node n, the effect on P_{ij} can be obtained by

$$\frac{\partial P_{ij}}{\partial PI_n} = \frac{\partial P_{ij}}{\partial V_i}\frac{\partial V_i}{\partial PI_n} + \frac{\partial P_{ij}}{\partial V_j}\frac{\partial V_j}{\partial PI_n} + \frac{\partial P_{ij}}{\partial \theta_i}\frac{\partial \theta_i}{\partial PI_n} + \frac{\partial P_{ij}}{\partial \theta_j}\frac{\partial \theta_j}{\partial PI_n} \tag{13}$$

Where, $\frac{\partial P_{ij}}{\partial V_i}$, $\frac{\partial P_{ij}}{\partial V_i}$, $\frac{\partial P_{ij}}{\partial \theta_i}$, and $\frac{\partial P_{ij}}{\partial \theta_j}$ can be calculated from (12) by calculating its partial derivates with regard to V_i, V_j, θ_i, θ_j.

In order to obtain the remaining parts in (13), sensitivity analysis is employed in (14) to represent the relationships between a change in nodal power and changes in voltage magnitudes and angles. Jacobian matrix in (14) is the one obtained in the last iteration of power flow analysis.

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial \theta} & \frac{\partial P}{\partial V} \\ \frac{\partial Q}{\partial \theta} & \frac{\partial Q}{\partial V} \end{bmatrix} \cdot \begin{bmatrix} \Delta\theta \\ \Delta V \end{bmatrix} = [J] \cdot \begin{bmatrix} \Delta\theta \\ \Delta V \end{bmatrix} \tag{14}$$

By applying (12) - (14), the effects of power injection at a node on circuits' power flows can be evaluated.

B. Sensitivity of Time to Reinforce to Circuit Power Flow

From (2), taking derivate of the time to reinforce with respect to circuit power flow gives

$$\frac{\partial n_l}{\partial P_l} = -\frac{1}{P_l \cdot \log(1+r)} \tag{15}$$

For a fixed LGR, the only factor that influences the sensitivity of time to reinforce to the power flow along a circuit is the circuit's loading level. The sensitivity of time to reinforce to the circuit's power flow can be either positive or negative. The negative sign implies that an increase in loading level reduces or brings forward time to reinforce and, a decrease in loading level increases or defers time to reinforce.

C. Sensitivity of Present Value of Future Reinforcement to Time to Reinforce

Similarly, from (3), taking derivative of PV_l with respect to n_l gives

$$\frac{\partial PV_l}{\partial n_l} = -\frac{Asset_l \cdot \log(1+d)}{(1+d)^{n_l}} \tag{16}$$

This formula represents how the change of time to reinforce affects the present value of future reinforcement. Here, because both asset cost and discount rate are fixed, the only factor influencing the level of sensitivity is time to reinforce. The negative sign indicates that a rise in time to reinforce lowers the present value of future reinforcement and, a fall in time to reinforce increases it.

D. Sensitivity of Present Value of Future Reinforcement to Nodal Injection

Combining (13), (15) and (16) into (17) and replacing n_l with (2) leads to the sensitivity of the present value of future reinforcement for a circuit to a nodal injection at node n

$$\frac{\partial PV_l}{\partial PI_n} = \frac{Asset_l}{P_l} \cdot \frac{\log(1+d)}{\log(1+r)} \cdot \left(\frac{P_l}{C_l}\right)^{\frac{\log(1+d)}{\log(1+r)}} \cdot \frac{\partial P_l}{\partial PI_n} \tag{17}$$

Where, $\frac{\partial P_l}{\partial PI_n}$ is from (13).

As can be seen from (17), for a circuit supporting the nodal injection at bus n, its cost, LGR, and the chosen discount rate are fixed. The factors that influence the change in the present value of future reinforcement as a result of the nodal injection are the circuit's loading level, the sensitivity of circuits' loading levels to the nodal injection. For circuits with low sensitivities to the nodal injection, even if they are heavily loaded, they will still have a low LRMC charge for the node, as the nodal injection causes very little change to the time to reinforce. On the other hand, even for lightly loaded circuits, if their sensitivities to the nodal injection are high, they will see larger LRMC charges for the node as the nodal injection triggers big change in time to reinforce. The chosen LGR is another factor affecting the calculated LRMC charges: a low LGR can lead to high charges and a high LGR can result in low charges, depending on the level of the circuit's utilization.

E. Long-run Marginal Cost

The LRMC charge for node n is the sum of LRMC charges over all circuits that support the nodal injection, multiplied by an annuity factor. The charge is given by,

$$LRMC_n = \sum_l \frac{\partial PV_l}{\partial PI_n} \cdot AnnuityFactor \tag{18}$$

IV. Revenue Reconciliation

It should be noted that neither incremental nor marginal charges may be able to recover the revenue allowed for Distribution Network Operators (DNOs). Revenue reconciliation process is therefore generally required to adjust the nodal incremental or marginal prices so that the revenue recovered from network charges can meet the target revenue. The mechanisms used by DNOs are equally important due to the fact that in practice, a large proportion of their revenue may be recovered through such scaling mechanism and it may have a significant impact on the relative level of nodal tariffs.

There are two commonly adopted revenue reconciliation approaches to adjust the nodal prices, namely "fixed adder" and "fixed multiplier"[17]. The fixed adder method adds/subtracts a constant amount to/from the nodal charges to make up for the revenue shortfall/surplus. The multiplier method scales the nodal charges by a constant factor corresponding to the ratio of the target revenue to the recovered revenue. Equations (19) and (20) describe how they adjust nodal LRIC or LRMC charges.

$$tariff_i = Charge_i + adder \tag{19}$$

$$tariff_i = Charge_i \cdot (1 + multiplier) \tag{20}$$

In the following section, the two methods are used to examine how LRIC and LRMC models affect the tariffs.

V. EXAMPLE DEMONSTRATION

A. Two-Busbar Test System Demonstration

The comparison of the two long-run charging methods is firstly carried out on a simple network shown in Fig. 1. Suppose that the rating of L_f is 45MW after security redundancy and its cost is £3,193,400. Taking 6.9% discount rate and 40 years life span leads to its annuity cost as £236,760/yr.

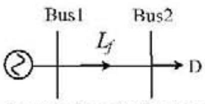
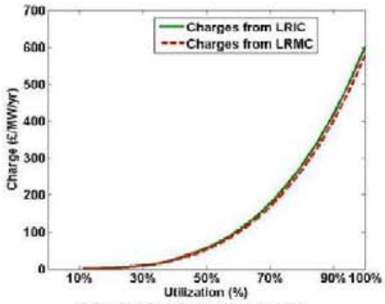
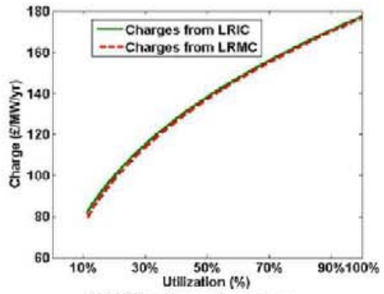


Fig. 1. Layout of two-busbar test system

As expected, if LRIC charges are calculated with a small injection - 0.1MW, LRMC yields similar results with LRIC in both low and high LGR cases and at both low and high circuit loading levels.



(a) 1.5% load growth rate case



(b) 5%load growth rate case

Fig. 2. Charge comparison with 1MW injection for LRIC

Fig. 2 compares the results with 1MW nodal injection for LRIC under two underlying growth rates, 1.5% and 5%. Generally, they are quite close at the most loading levels, with few exceptions. In the small LGR case, the difference in charges from the two methods grows with the increasing circuit's utilization. In the high LGR case, the charge difference decreases with the increase of loading level.

The apparent difference in charges is due to the different calculation concepts of the two approaches, demonstrated in Fig.3. LRIC is achieved through simulating the difference in the present value of future reinforcement with and without the injection, while LRMC charge is calculated through a single function representing three partial differentiations initiated by the nodal injection. If the LRIC/LRMC cost function is not steep with respect to the circuit's utilization, the difference between LRMC and LRIC charges should be very small.

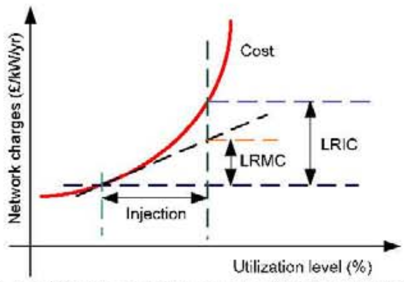
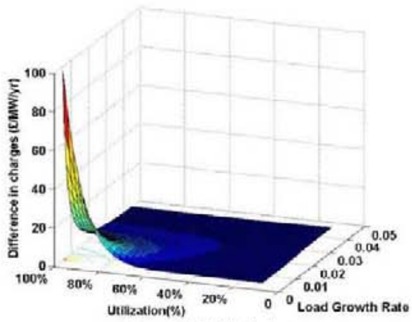
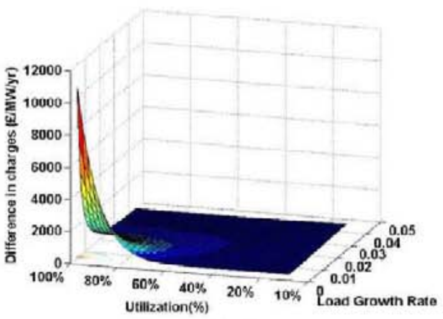


Fig. 3. Different calculation concepts of LRIC and LRMC

Two three-dimensional graphs in Fig. 4 demonstrate the difference in charges from the two approaches under different LGRs and at different circuits' loading levels. As seen from Fig. 4, the large difference is seen when the LGR is lower than 1% and the utilization is higher than 70%.



(a) 0.1MW injection case

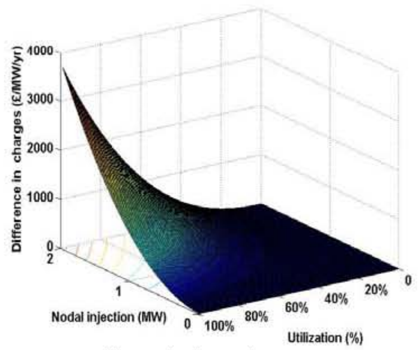


(b) 1MW injection case

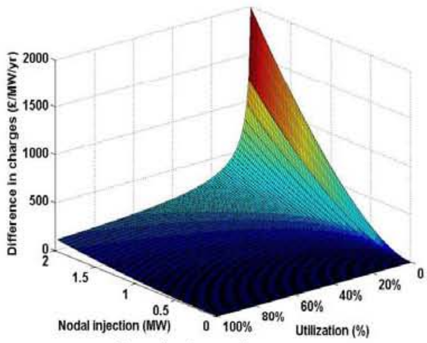
Fig. 4. Difference in charges from the two methods

Two graphs in Fig. 5 show the difference in charges by varying the size of the nodal injection and the level of circuit utilization levels under 1.5% and 5% LGRs. Fig. 5.a shows that in the case of 1.5% LGR, the size of the nodal injection for LRIC has little influence on the difference when the circuit utilization is low, especially if the injection is smaller than

0.5MW. However, the difference grows apparent with the increasing nodal injection when the circuit utilization is high. It is due to the fact that a big nodal injection will greatly bring forward time to reinforce the circuit. In the high LGR case given in Fig. 5.b, the big difference only appears when the nodal injection is greater than about 0.5MW and the utilization is low. It is due to the steep slope of the LRMC cost function with respect to the circuit's loading level given in Fig. 3.



(a) 1.5% load growth rate case



(b) 5% load growth rate case

Fig. 5. Difference in charges from the two methods

B. *Demonstration on a Practical System*

In this section, the comparison of LRIC and LRMC pricing methods is carried out on a practical Grid Supply Point (GSP) area given in Fig. 6.

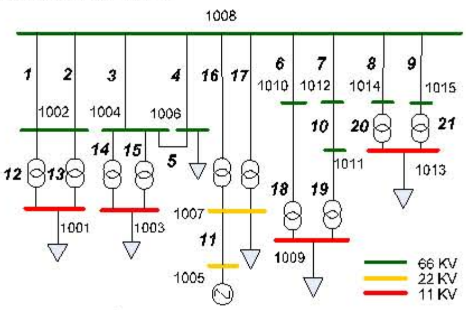


Fig. 6. A GSP area test system

The rationale in comparing the two methods on a practical system is that a nodal increment is likely to impact many circuits in the network. The difference between the two methods for each circuit might be modest, but accumulating these differences over all supporting circuits for a node could potentially produces large difference. The comparison is carried out under two conditions: i) two underlying LGRs: 1% and 5%; ii) two loading levels: base loading level and scaled-up level (by 20%). An injection of 1MW is employed for LRIC model. The comparisons are in terms of nodal LRIC and LRMC charges and tariffs.

For this practical system, if LRIC is adopted, it takes a computer 157 milliseconds to calculate the nodal charges for every single node in the network. But for LRMC, it only takes 51milliseconds on the same computer - 1/3 of the computational effort of the LRIC. For a large-scale system with 2000 nodes, it takes the computer 12 seconds to calculate LRIC charge for a single node and approximately 6 hours and 40minutes in total. In contrast, it takes only 0.5 second to compute LRMC charges for a single node and takes barely 17 minutes in total.

(1) Base case – base loading level

Table I gives nodal charges from LRIC and LRMC approaches under the base loading level. To assist the analysis, Fg. 7 depicts the utilization levels of branches in the base loading case. As seen from it, the most heavily loaded circuit is line No. 4 linking bus 1008 and bus 1006. Transformers 12-17 also have high loading levels.

TABLE I
COMPARISON OF CHARGES UNDER TWO LOAD GROWTH RATES (£/KW/YR)

Bus No.	LGR=1%			LGR=5%		
	LRIC	LRMC	Diff.	LRIC	LRMC	Diff.
1001	4.265	3.82	0.444	5.886	5.84	0.042
1002	0.607	0.546	0.061	4.419	4.39	0.03
1003	20.21	19.06	1.149	10.14	10.10	0.049
1004	18.61	17.61	1.001	9.04	8.997	0.04
1005	1.963	1.75	0.211	1.285	1.275	0.01
1006	18.16	17.18	0.979	6.698	6.66	0.039
1007	1.963	1.752	0.211	1.285	1.275	0.01
1009	0.122	0.097	0.025	10.16	10.02	0.143
1010	0.025	0.019	0.006	6.116	5.974	0.142
1011	0.245	0.16	0.085	12.94	12.61	0.329
1012	0.241	0.157	0.084	11.43	11.14	0.292
1013	0	0	0	2.053	1.961	0.092
1014	0	0	0	1.242	1.15	0.092
1015	0	0	0	2.3	2.121	0.179

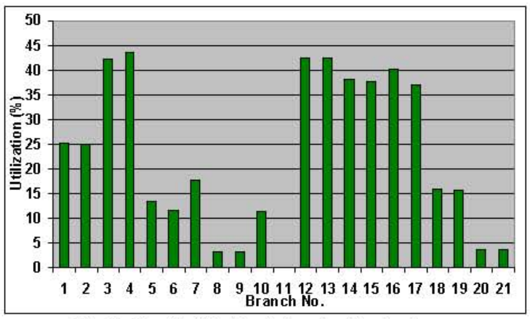


Fig. 7. Circuit utilization in base loading level case

When LGR is at 1%, the differences in charges from the two approaches are large for nodes 1001-1007, as they are supported by relatively highly utilized circuits. Also can be observed is that nodes 1009-1015 are supported by lightly loaded circuits, and correspondingly their charges are close to 0. In the 5% LGR case, the charges at nodes 1009-1015 become significantly larger because when the underlying LGR is higher, the time to reinforce network assets is nearer and therefore a nodal injection would have a greater impact on the present value of future investment. In comparison, nodes 1003-1006 are supported by heavily utilized circuits, their charges decrease as the LGR increases. Generally, the conclusions from the simple example are still applicable here: cases with small LGRs and high loading levels see big differences in LRIC and LRMC charges. The conclusions are also true for cases with large LGRs and low loading levels.

Two most commonly used revenue reconciliation approaches-fixed adder and fixed multiplier are employed here to demonstrate the degree of adjustments required to meet the target revenue, their relative merits and impacts on LRIC and LRMC charges. The tariffs are given in tables II and III.

TABLE II
COMPARISON OF TARIFFS USING FIXED ADDER METHOD (£/KW/YR)

Bus No.	LGR=1%		LGR=5%	
	LRIC	LRMC	LRIC	LRMC
1001	6.659	6.806	11.073	11.073
1002	3.001	3.532	9.606	9.623
1003	22.604	22.046	15.327	15.333
1004	21.004	20.596	14.227	14.230
1005	4.357	4.736	6.472	6.508
1006	20.554	20.166	11.885	11.893
1007	4.357	4.738	6.472	6.508
1009	2.516	3.083	15.347	15.253
1010	2.419	3.005	11.303	11.207
1011	2.639	3.146	18.127	17.843
1012	2.635	3.143	16.617	16.373
1013	2.394	2.986	7.240	7.194
1014	2.394	2.986	6.429	6.383
1015	2.394	2.986	7.487	7.354

From table II, when LGR is 1%, the largest difference in LRIC and LRMC tariffs is 0.592£/kW/yr for nodes 1013-1015. It is because that although these nodes have zero charges, fixed adder allocates the under-recovered revenue equally to all network nodes, thus resulting in the fixed adder of £2.394/kW/yr for LRIC and £2.986/kW/yr for LRMC. When LGR increases to 5%, the largest difference decreases to 0.284£/kW/yr (for node 1011). For all other nodes, the charges from the LRIC and LRMC approaches yield quite similar tariffs. Compared with 1% LGR case, tariffs for this case are much higher, because that when loads grow faster, time to reinforce circuits will be nearer, leading to high charges. From the table, it can also be seen that the fixed adder approach maintains the relative differences in nodal tariffs the same as the nodal charges, therefore minimizing the potential distortion to the economic charges.

As for the fixed multiplier method, it amplifies the relative difference of nodal charges, as a result, higher charges getting even higher tariffs and 0 charges remaining 0, as shown in table III. For the low LGR case, the biggest difference in LRIC and LRMC tariffs is 0.357 £/kW/yr for node 1004, which has been reduced from the original difference of 1.001£/kW/yr in charges, as LRIC and LRMC methods see different multipliers, 0.25 for LRIC and 0.34 for LRMC. When it comes to the high LGR case, the tariffs reconciled from LRIC and LRMC charges are quite close and the biggest difference is for node 1011, counted as 0.433£/kW/yr. Compared with the difference of 0.329£/kW/yr in charges (in table I), this tariff difference is amplified by the multiplier. Potentially, if there are few excessively high nodal charges, a modest multiplier would lead to extremely high tariffs for the few nodes.

TABLE III
COMPARISON OF TARIFFS USING FIXED MULTIPLIER METHOD (£/KW/YR)

Bus No.	LGR=1%		LGR=5%	
	LRIC	LRMC	LRIC	LRMC
1001	5.342	5.134	10.600	10.592
1002	0.760	0.734	7.958	7.962
1003	25.315	25.617	18.261	18.318
1004	23.311	23.668	16.280	16.318
1005	2.459	2.352	2.314	2.312
1006	22.747	23.090	12.062	12.079
1007	2.459	2.355	2.314	2.312
1009	0.153	0.130	18.297	18.173
1010	0.031	0.026	11.014	10.835
1011	0.307	0.215	23.303	22.871
1012	0.302	0.211	20.584	20.204
1013	0.000	0.000	3.697	3.557
1014	0.000	0.000	2.237	2.086
1015	0.000	0.000	4.142	3.847

(2) Higher loading level – 20% scaling up

In this part, all loads are scaled up by 20%, thus increasing all circuits' utilization by approximately 20%. The scaled up loading levels of all branches are given in Fig. 8.

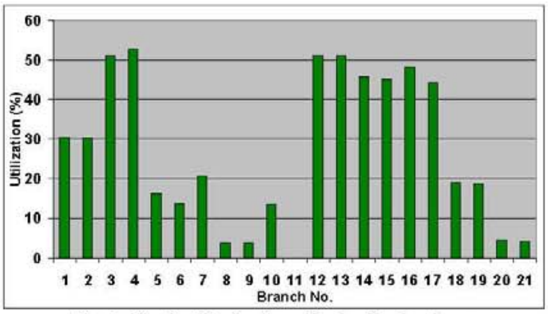


Fig. 8. Circuit utilization in scaling loading level case

Table IV summarizes the charges from the two charging approaches for the two LGR cases. Obviously, charges follow the same patterns as the base case, but they are much higher because of the increased circuit utilization levels. Compared with results given by table I, the increments in charges are similar for both approaches, where the lower LGR sees greater increments in charges and the high LGR sees small increments.

Tables V provides tariffs calculated using fixed adder method. In the low LGR case, the fixed adder approach gives negative tariffs for some nodes. It is due to that charges are dominated by high charges at buses 1003, 1004 and 1006, which are supported by highly utilized circuits. The revenue recovered from these three nodes alone already exceeds the allowed revenue. Consequently, a negative adder is obtained, leading to negative tariffs for the majority of the nodes in the system. When the LGR rises up to 5%, tariffs for all nodes are positive because of the positive adder and the difference in tariffs becomes small compared with the 1% LGR case.

TABLE IV
COMPARISON OF CHARGES UNDER TWO LOAD GROWTH RATES (£/KW/YR)

Bus	LGR=1%			LGR=5%		
No.	LRIC	LRMC	Diff.	LRIC	LRMC	Diff.
1001	12.52	11.43	1.087	6.29	6.25	0.037
1002	1.757	1.61	0.146	4.70	4.68	0.026
1003	60.19	57.35	2.836	10.87	10.83	0.044
1004	55.21	52.76	2.451	9.66	9.62	0.036
1005	5.39	4.894	0.496	1.38	1.38	0.008
1006	53.87	51.47	2.398	7.16	7.12	0.035
1007	5.39	4.89	0.496	1.38	1.36	0.008
1009	0.39	0.32	0.068	11.21	11.08	0.134
1010	0.076	0.06	0.014	6.57	6.45	0.125
1011	0.78	0.54	0.237	14.45	14.14	0.314
1012	0.77	0.53	0.233	12.85	12.56	0.282
1013	0	0	0.000	2.18	2.1	0.082
1014	0	0	0.000	1.31	1.23	0.083
1015	0	0	0.000	2.43	2.27	0.162

TABLE V
COMPARISON OF TARIFFS USING FIXED ADDER METHOD (£/KW/YR)

Bus	LGR=1%		LGR=5%	
No.	LRIC	LRMC	LRIC	LRMC
1001	-5.196	-4.834	9.036	9.042
1002	-15.959	-14.654	7.446	7.472
1003	42.474	41.086	13.616	13.622
1004	37.494	36.496	12.406	12.412
1005	-12.326	-11.370	4.126	4.172
1006	36.154	35.206	9.906	9.912
1007	-12.326	-11.374	4.126	4.152
1009	-17.326	-15.944	13.956	13.872
1010	-17.640	-16.204	9.316	9.242
1011	-16.936	-15.724	17.196	16.932
1012	-16.946	-15.734	15.596	15.352
1013	-17.716	-16.264	4.926	4.892
1014	-17.716	-16.264	4.056	4.022
1015	-17.716	-16.264	5.176	5.062

TABLE VI
COMPARISON OF TARIFFS USING FIXED MULTIPLIER METHOD (£/KW/YR)

Bus	LGR=1%		LGR=5%	
No.	LRIC	LRMC	LRIC	LRMC
1001	4.436	4.276	8.767	8.769
1002	0.622	0.602	6.551	6.566
1003	21.325	21.454	15.150	15.194
1004	19.560	19.737	13.464	13.497
1005	1.910	1.831	1.923	1.936
1006	19.086	19.254	9.979	9.989
1007	1.910	1.829	1.923	1.908
1009	0.138	0.120	15.624	15.545
1010	0.027	0.022	9.157	9.049
1011	0.276	0.202	20.140	19.838
1012	0.273	0.198	17.910	17.621
1013	0.000	0.000	3.038	2.946
1014	0.000	0.000	1.826	1.726
1015	0.000	0.000	3.387	3.185

As for the tariffs from the fixed multiplier method given by table VI, compared with the base case results in table III, they become a little bit smaller for all nodes because of the increased demand. However, compared with the tariffs calculated with the fixed adder approach, there is no negative tariff obtained in the 1% LGR case. On the other hand, all tariffs in this case are smaller than the charges provided in table IV as a smaller fixed multiplier scales down all charges proportionally.

The revenue reconciliation mechanism used by a DNO is very important as it decides how LRIC or LRMC charges should be shaped into tariffs seen by network users. In practice, a large proportion of DNOs' revenue may be recovered through the reconciliation mechanism. The fixed adder approach can maintain the same level of differentiation between nodal tariffs, thus minimizing any distortion over the pure incremental/marginal costs. In contrast, the fixed multiplier approach maintains the relativity between nodal tariffs, but the relativity is proportionally amplified by the same level. This could be considered as the distortion of the cost signals that network customers would see. The fixed adder approach is thus preferred by the majority of DNOs in the UK.

VI. DISCUSSIONS

Generally, the difference in charges and tariffs from LRIC and LRMC approaches is affected by three major factors: the circuit's utilization level, LGR and the size of nodal injection. For the majority of the operating conditions in practice, they would yield very similar results. LRMC is a good approximation to LRIC except for few extreme cases, where LRIC should be used to better reflect the extent of the impacts on the network imposed by a nodal power increment. Additional benefit with LRMC is that the interim results from it can provide further insights into how different factors, such as how the circuit loading level and LGR would impact on the long-term development costs and to what extent they would impact. Such information is not readily available from the LRIC charging model.

It should be noted that locational charges set by either LRIC or LRMC are to recover the network fixed costs. This is of paramount importance to DNOs at the moment when they are expecting to connect substantial amount of Distribution Generators (DGs). Efficient locational messages will incentivise the prospective DGs to connect to appropriate sites so as to minimise the network development costs.

The core of the LRIC charging model proposed in [15] has been adopted by three of the UK's major distributors, Western Power Distribution (WPD, UK) Électricité de France (EDF) and CE Electric.

The long-run marginal and incremental cost pricing models provide locational messages to minimise the network development costs. The short-run and long-run pricing should be complementary and interactive. The short-run locational marginal pricing aims to minimise congestion and losses, thus improving the efficiency of the existing network and delaying the needed network upgrades. Efficient long-run messages should encourage prospective network customers to better utilize the existing network, thus reducing congestion and losses in the long run. Network operators should strike the right balance between network investment costs and network congestion and losses costs, which should be reflected in the interaction between the long-run and short-run pricing.

VII. Conclusions

In this paper, a novel LRMC charging method based on analytical approach is proposed, which directly relates the nodal power increment to the change in the present value of future network investment. Results on the two systems using the proposed method are compared and contrasted with those from the LRIC approach. Based on the extensive analysis, the following key findings can be concluded:

(i) In terms of accuracy, the LRIC and LRMC approaches yield quite similar results when the size of the nodal injection for LRIC is small. The biggest difference appears when circuits are highly loaded and LGR is small. When the injection becomes large, the discrepancies between the two approaches become apparent and the biggest difference shows up when circuits are lightly loaded and LGR is high. As for tariffs, they are highly dependant on charges, and largely follow the same pattern as for the charges.

(ii) In terms of speed, the LRIC needs to run power flow analysis twice for each nodal injection in order to examine the effects of an injection on the long-term development costs. For a large system, the computational burden grows exponentially with the increase in the size of the network. The proposed LRMC, on the other hand, saves significant computational time for large-scale networks by utilizing sensitivity analysis, avoiding running power flow analysis for every single nodal injection.

(iii) In terms of flexibility, the LRIC model, working through simulation approach, can examine the impacts imposed on a network by any size of injection. But, the proposed LRMC can only accurately represent a very small change. For a large size of injection, the charges obtained with LRMC can deviate from those calculated with the LRIC.

(iv) Finally, revenue reconciliation process is very important in how it might shape the relative difference in LRIC and LRMC charges. The fixed adder approach uniformly scales up/down all nodal charges, hence preserving the absolute difference in nodal charges. The fixed multiplier, on the other hand, amplifies the nodal relativity. If the amplification becomes significant, it could considerably distort the impact that a nodal power injection might have on the network development cost. As a consequence, the industry in general favors the fixed adder approach over the fixed multiplier.

To summarize, the proposed LRMC charging model produces very similar results with that of LRIC for the majority of operating conditions. It is a good supplement to LRIC method not only because of its computational efficiency but also because of the additional insights that the interim results offer for understanding the charging problems and the consequential charges.

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IX. Biographies

Chenghong Gu (S'09) was born in Anhui province, China. He received his Master degree in electrical engineering from Shanghai Jiao Tong University, Shanghai, China, in 2007. Now, he is a PhD student with University of Bath, U.K. His major research is in the area of power system economics and planning.

Furong Li (M'00, SM'09) was born in Shannxi province, China. She received the B.Eng. degree in electrical engineering from Hohai University, Nanjing, China, in 1990 and the Ph.D. degree from Liverpool John Moores University, Liverpool, U.K., in 1997. She then took up a lectureship with Department of Electronic & Electrical Engineering, University of Bath, where she is a Reader in the Power and Energy Systems Group at the University of Bath, Bath, U.K. Her major research interest is in the area of power system planning, analysis, and power system economics.

Application of Long-run Network Charging to Large-scale Systems

Chenghong Gu[1], Furong Li[1], and Lihong Gu[2]

Abstract-- **Charging methodology is one important scheme in the deregulated environment in the way that it can be utilized to recover the investment cost from network users according to their different impact on the network. The long-run incremental cost (LRIC) pricing methodology developed by University of Bath in conjunction with Western Power Distribution (WPD, UK) and Ofgem (the office of gas and electricity markets, UK) has drawn lots of attention from industry and academic circles and found its application in practice. Compared with the existing long-run cost pricing methodologies, this charging model can produce forward-looking charges that reflect both the extent of the network needed to serve the generation/demand and the degree to which the network is utilized.**

This paper examines the practical issues concerning implementation of this charging model in order to assist its utilization in the future. Firstly, the calculation and selection of the parameters, load growth rate, contingency factor, asset costs, that would impact charge evaluation are discussed, followed by the focus on some particular issues concerning them. Thereafter, the technical problems which might appear while applying this charging model to large-scale practical systems are dressed and a few feasible solutions are provided. This charging model, at last, is demonstrated on a practical system taken from the U.K. network.

Index Terms-- **Long-run network charging, load growth rate, contingency analysis, discount rate**

I. Nomenclature

NETWORK charges are charges against network users for their use of a network in order to recover the costs of capital, operation and maintenance of a network and provide forward-looking, efficient messages to both consumers and generators[1]. Network charges, therefore, should be able to truly reflect the extent of the use of the network by network users. Efficient charges can help to release constraints and congestion in the network, deferring prospective network expansion or reinforcement [2, 3].

The present pricing methodology adopted by the majority of the distribution network operators (DNOs), the distribution reinforcement model (DRM) in the U.K., however, cannot provide locational economic signals as the costs of network assets are averaged at each voltage level[4]. Long-run cost charging methodologies, due to its merits of being able to reflect the cost of future network reinforcement caused by the nodal increment are recognized as more economically efficient. Most long-run cost pricing methods evaluate costs associated with projected demand/generation pattern and subsequently allocate the costs among new and existing customers. These approaches, however, can only passively react to a set of projected patterns of future generation or demand, failing to proactively influence the patterns of future generation or demand through economic incentives. Up to 2005, investment cost-related pricing (ICRP) utilized in the U.K., which works based on distance or length of circuits, is the most advanced long-run pricing model[5].

One recent development in long-run cost pricing methodology is the long-run incremental cost (LRIC) pricing methodology developed by the University of Bath in conjunction with Western Power Distribution (WPD, U.K.) and Ofgem (the office of gas and electricity markets, U.K.)[6]. This charging approach examines how a nodal increment of generation/demand might impact the time to reinforce system assets and then translate the time change into charges. The decision concerning of being penalty or reward is based on whether the nodal perturbation advances future investment or defers it. This method, compared with existing long-run cost pricing approaches, can produce cost-effective charges that reflect both the extent of the network needed to serve the generation or demand and the degree to which the network is utilized[7]. As being able to send forward-looking signals to influence prospective network connections, this charging model has been adopted by WPD in its EHV network and is being under consideration by several other DNOs in the U.K.

In this charging model, the time to reinforce is evaluated by assessing the time for a loading level to reach the full capacity of system components under a certain load growth rate with and without the nodal injection. The proper modeling and calculation of load growth rate, as a result, is essential for this charging model. Furthermore, in order to cater N-1 security principle, part of components' spare capacity should be reserved for contingency case. This is achieved in the LRIC model by defining a contingency factor to assess the maximum allowed power flow the component can carry in normal conditions[8]. In addition, while applying this charging model to large-scale systems, some technical problems might appear, such as time consumption, connectivity of network in contingency analysis, computational time. All these modeling and technical issues

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In this paper, we will discuss the selection and calculation of load growth rate, contingency factor, and asset costs that would to great extent impact charge evaluation and examine the technical issues of applying the LRIC charging model to practical large-scale systems. The modeling and selection of the those major parameters are firstly examined by focusing on the underlying information they carry for LRIC charging model, followed by the discussion on some particular problems concerned. Thereafter, the potential technical issues appearing while applying this charging model to large-scale system are dressed and some feasible solutions are presented. Lastly, this charging model is demonstrated on a practical large-scale system with over 2000 busbars taken from the U.K. network.

The rest of the paper is organized as follows: section II gives a brief introduction to LRIC charging approach. In section III, the parameters affecting LRIC charging are presented and discussed. Section IV presents some potential technical problem of implementation LRIC charging model and their feasible solutions. An example is provided in section V. Finally, some conclusions are drawn in section VI.

II. Long-run Network Charging Model

In the original LRIC pricing model[6], for components in network that are affected by a nodal injection, there will be a cost or a credit associated for the injection according to whether the network investment is accelerated or deferred. The LRIC model has the following three implementation steps.

A. Present Value of Future Investment

If a circuit l has a maximum allowed power flow of C_l, supporting a power flow of P_l, the number of years it takes P_l to grow to C_l under a given LGR, r, can be determined with

$$C_l = P_l \cdot (1+r)^{n_l} \tag{1}$$

Where, n_l is the number of years taking P_l to reach C_l.

Rearranging (1) and taking the logarithm of it gives

$$n_l = \frac{\log C_l - \log P_l}{\log(1+r)} \tag{2}$$

Assume that investment will occur in the n_l-*th* year when the circuit utilization reaches C_l and with a chosen discount rate of d, the present value of future investment will be

$$PV_l = \frac{Asset_l}{(1+d)^{n_l}} \tag{3}$$

Where, $Asset_l$ is the modern equivalent asset cost.

B. Cost Associated with Power Increment

If power flow change along line l is ΔP_l as a result of a nodal injection, the time horizon of future reinforcement will change from year n_l to year n_{lnew}, defined by

$$C_l = (P_l + \Delta P_l) \cdot (1+r)^{n_{lnew}} \tag{4}$$

Equation (4) gives the new investment horizon n_{lnew}

$$n_{lnew} = \frac{\log C_l - \log(P_l + \Delta P_l)}{\log(1+r)} \tag{5}$$

The new present value of future reinforcement becomes,

$$PV_{lnew} = \frac{Asset_l}{(1+d)^{n_{lnew}}} \tag{6}$$

The change in present value as a result of the injection is given by

$$g(r) = \Delta PV_l = Asset_l \cdot \left(\frac{1}{(1+d)^{n_{lnew}}} - \frac{1}{(1+d)^{n_l}} \right) \tag{7}$$

The incremental cost for circuit l is the annuitized change in present value of future investment over its life span,

$$\Delta IC_l = \Delta PV_l \cdot AnnuityFactor \tag{8}$$

C. Long-run Incremental Cost

The nodal LRIC charges for a node are the summation of incremental cost over all circuits supporting it, given by

$$LRIC_i = \frac{\sum_l \Delta IC_l}{\Delta PI_i} \tag{9}$$

Where, ΔPI_i is the size of power injection at node i, and here we assign it to be 1MW.

D. Flowchart of LRIC

The flowchart for LRIC charge evaluation can be summarized in Fig. 1, the core of which is contingency analysis, incremental power analysis and charge assessment.

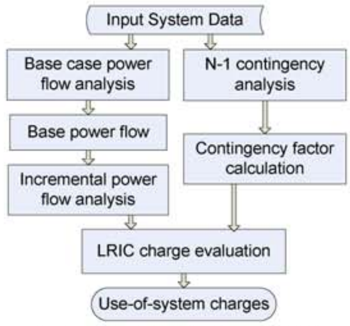

Fig.1. Flowchart of LRIC charging model

In the following sections, the major issues concerning charges evaluation will be discussed.

III. Parameters Influencing LRIC Charging

A. Load Growth Rate and Circuit Load Growth Rate

Demand growth represents the increase in energy demand over time, occurring through natural growth of a service territory resulting from the increased prosperity, productivity or population. Load growth rate is an averaged index derived by annuitizing the load growth in a particular time span. In the U.K., for example, National Grid Company (NGC, UK) forecasted electricity demand met via the Western Power Distribution (WPD, UK) network to increase to 15TWh by 2013-14, an average growth rate of 1.4% per year [9].

In the LRIC charging model, in order to simplify the process of assessing time to reinforce without and with nodal injection, (1) and (4) assume uniform loading growth rate along each circuit. In reality, however, loads at different buses may grow diversified loading growth rate for each circuit. In this case, the uniform loading growth rate is no longer practical. In order to cope with this problem, a two-run power flow strategy can be used to assess the true circuit loading growth rate caused by the different load growth rate at each busbar. In the first run, a basic power flow analysis is executed to compute the base flow along each circuit. In the second run, all loads are scaled up/down according to their growth rates and then calculate all circuit flow. The desired circuit loading growth rate can subsequently be derived with

$$r = \frac{P_l}{P_{l,0}} \tag{10}$$

Where, P_l is the power flow along circuit l in the second run and $P_{l,0}$ is the base case flow along it.

Further, it can be found that the majority of the previous work concerning LRIC charging model is limited on the assumption that a fixed LGR can be predicted [5, 6, 10]. For developed regions/countries, it is less likely for load growth to have huge variations over long term since load growth has already saturated and become relatively steady. But for medium developing regions/countries, load growth might have a range of plausible values varying considerably with time, leading to uncertain load growth rate, which, in turn, would impose great difficulties on charge evaluation. Paper [11] proposed a novel LRIC charging methodology for evaluating charges with consideration of uncertainty in load growth through fuzzy set theory. The uncertain LGR is modeled by a range of potential values, each with its own confidence level. Then, the fuzzy model is mapped into charging method based on fuzzy extension principle method that respects the relationship between LGR and long-run network charges. Thereafter, defuzzificaion approach can be employed to derive crisp charges. Results show that the proposed fuzzy load growth rate model can effectively capture the uncertainty in future load growth and the defuzzified charges still maintain the economic signals sent to network users to guide their potential connections.

B. Contingency Factor

In practice, all networks are designed to withstand credible contingencies, which is also compulsory for LRIC pricing. It is important for it to recognize the level of spare capacity reserved for catering N-1 contingency to ensure network security, although this might come at significant costs for network development.

Paper [8] proposes a new approach that can establish a direct link between nodal generation/demand increment and change in investment costs while ensuring network security. The investment cost is reflected by the change in the spare capacity of a network asset from a nodal injection, which is then translated into investment horizon, leading to the change in the present value of future investment. The security is reflected in the pricing model through conducting a full N-1 contingency analysis to decide the maximum allowed power flow along each circuit, from which the time horizon of future investment is determined accordingly. In the paper, contingency factor is defined as the ratio of the maximum contingency flow along a circuit over its base flow in normal condition [8]. The maximum allowed power flow for each circuit to carry considering the additional power flow it has to carry in contingency situation is given by

$$C_l = \frac{Rated\ Capacity_l}{Contingency\ Factor_l} \tag{11}$$

For a given load growth rate, the time horizon of future investment will be the time taking the load to grow from current loading level to the maximum or requirement of reinforcement loading margin (under contingency), instead of the full loading level (rated capacity), given by

$$\frac{C_l}{CF} = D \times (1+r)^n \tag{12}$$

With the contingency factor term, LRIC can make sure that sufficient spare capacity is allocated to ensure network security under contingent situation.

C. Component Reinforcement Cost

Generally, the reinforcement costs of circuits or transformers need to be recovered though LRIC charging model. Based on their different functions or ownerships, these branches can be roughly divided into two different categories: i)transformer/circuit branches which have certain reinforcement costs; ii) transformer/circuit branches which have no costs (zero-cost branches). Those zero-cost branches are mainly branches, whose costs have been recovered from network users, or branches which are owned by network users, or branches which are used to connect different part of the substations, such circuit breaker, and switches.

All the components' costs are annuitized through annuity factor into annuity costs, which are the actual amount of reinforcement costs that are recovered each year.

IV. Practical Issues of Implementing LRIC Charging

A. Sensitivity Analysis

In order to evaluate charges for one single node, two-run load flow analysis is executed in order to assess the effect from the nodal injection imposed on system assets. The shortcoming of this simulation approach is that it would spend much longer time on calculating charges for large-scale systems. The computational time rises exponentially with the increasing number of busbars in the network.

In paper[12], a sensitivity-based charging model is proposed following the same principle of [6], but utilizes sensitivity analysis to significantly reduce the computational burden for large systems. In the proposed approach, the change of present value of future reinforcement due to a nodal power increment is represented by three partial differentiations: i) sensitivity of circuit loading level with regard to nodal injection, ii) sensitivity of time to reinforce with respect to circuit loading level, and iii) sensitivity of the present value of future reinforcement with respect to time to reinforce, given as

$$\frac{\partial PV_l}{\partial PI_n} = \frac{Asset_l}{P_l} \cdot \frac{\log(1+d)}{\log(1+r)} \cdot \frac{1}{(1+d)^{n_l}} \cdot \frac{\partial P_l}{\partial PI_n} \tag{13}$$

As demonstrated in the example, in terms of accuracy, the proposed approach yields quite similar results compared with LRIC when the nodal injection for LRIC is small. The biggest difference appears when circuits are highly loaded and LGR is small. When the injection becomes large, the discrepancies between the two approaches become apparent and the biggest difference shows up when circuits are lightly loaded and LGR is very high. In terms of speed, the original LRIC needs to run power flow analysis for each nodal injection twice in order to examine the effects of the injection on the long-term development costs. The proposed method, on the other hand, working through sensitivity analysis, can save significant computational time especially for large-scale networks.

Conclusively, the proposed charging calculation method is a promising supplement to LRIC method not only because of its computational efficiency but also because of the additional insights that the interim results can offer for the understanding of the charging problems and the consequential charges.

B. Contingency Analysis

Another problem is with contingency analysis, which is the most heavily time-consuming part in LRIC. Further, when or more components are out of service, in quite few cases, the system might be split into one more parts. In order to tackle theses problems, some special techniques should be taken.

In the LRIC, the contingency factor utilized to assess the spare capacity reserved for security purpose of each component is obtained by performing contingency analysis. The contingency level is usually chosen according to the desired security level. For distribution network, in most case, N-1 level contingency would be enough to secure the network according to the P2/6 document (U.K.). While in some special cases, high level security might be required, which means that, N-2 or even higher level of contingency (N-x, x>2) should be considered. In this condition, a man-picked contingency list is needed for the contingency analysis and in order to find out the most serious contingency case for each component, all the contingency cases are assessed.

One potential problem appearing at this stage is network islanding caused by the outage of certain network components. When these components are out of service, the network might be split into more than one part, leading to the non-convergence of power flow analysis. In this case, a scheme that can detect network connectivity is required in order to determine the true structure of the network. Generally, a two-step method can work properly to cope with the network islanding problem: i) if the islanding part does not have any generators or power sources, all the components are flagged as out to be moved out; ii) if the islanding part has generators or power sources, the bus with the biggest size of generator is chosen as the slack bus for the part to run contingency analysis.

Another problem at this stage is with time consumption. For a large-scale system, the number of considered contingency cases can be huge, leading to great computational burden. In some particular cases, voltage regulation might also be considered in order to improve network voltage profile and consequently, more runs of power flow should be executed. The ultimate effect is soaring computational time, which increases with the rise in the number of network busbars. One feasible solution is to initialize each contingency case analysis with the base power flow results, since the states of most components in the network do not divert too far from their base states, especially for large-scale system. As a result, power flow would need less times of iteration to reach to the preset resolution. Other potential strategies are to use PQ decoupled load flow analysis if the precision in contingency factors is not the primary concern. The PQ decoupled power flow strategy can dramatically reduce computational time, while still providing acceptable results for contingency analysis.

C. Incremental Power Flow Calculation

Incremental power flow analysis is executed to determine how the future network users would affect the existing network components, which can be calculated either by simulation approach or sensitivity analysis forehead mentioned. The method for calculating the incremental flows should be carefully selected in order to ensure that the incremental flows along each component with and without nodal injection are accurate enough to reflect network users' effect on those components.

Normally, nodal injection is chosen as 0.1MW, which means that power flow analysis approach should be able to capture the change in incremental flows due to the injection. As discussed in section IV, simulation approach is more accurate than sensitivity analysis, but its shortcoming is time consumption especially for large-scale systems. Sensitivity method, although not as accurate as simulation approach, can save computational time dramatically and produce acceptable results and is a quite good alternative to simulation method.

V. Test System Demonstration

The LRIC charging model is demonstrated on a large-scale system taken from WPD network, which consists of more than 2000 nodes. Fig. 2 is the geographical map of the UK network and the chosen system is located in its southeast.

Fig. 2. Geographical map of the UK network.

In the calculation, load growth rate is taken as 1% uniformly, discount rate is chosen as 6.9. The contingency factors for all components are calculated by running the contingency list chosen by the network operator. It takes simulation approach about 12 seconds to calculate charges for one single node and approximately 400minutes in total. By contrast, it takes sensitivity only 0.5 second to compute charges for a single node and in total takes barely 17 minutes to calculate charges for all load busbars. In order to simply the analysis, this example considers only the basic situation for charge evaluation with simulation method.

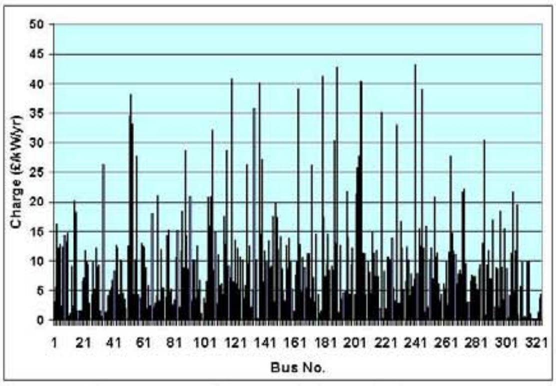

Fig. 3. Long-run incremental charges for the test system

Fig 3 demonstrates the charges for all the load busbars. It can be observed that charges for the all the load busbars vary greatly, depending on the impact on system assets supporting the busbar imposed by nodal injection from this busbar. The maximum charges is 43.153 £/kW/yr for busbar 241, which is served with quite heavily loaded components.

If non-uniform load growth rate is taken into consideration, the circuit load growth rate can be computed by running two times of load flow analysis, with the base one and the one with all loads scaled up/down according to their load growth rate. As 0.1MW nodal injection is taken for the simulation method, the resultant charges from sensitivity analysis should not deviate too much from those from the simulation.

The varying charges can effectively reflect the effect of network users putting on the system components, and in addition, these charges can be sent to potential network users to influence their prospective connection sites and sizes. As can be seen, no matter the sizes of the networks, LRIC is an effect charging algorithm to recover the investment in the network from DNOs, and make the development of the network towards more reliable and efficient direction.

VI. Conclusion

Long-run incremental cost (LRIC) pricing methodology is one of the most advanced charging models, which cannot only reflect the impact from network users imposed on the network but also to influence potential network connections. Ofgem in the UK has successfully pushed charging scheme reform through the evidence given by this charging model.

In this paper, we focused on the selection of load growth rate, contingency factor, and asset costs, which would affect the resultant charges. The discussion of potential problems concerning them can be helpful while utilizing LRIC to actual networks. In addition, the technical issues which might be confronted while applying this charging model to large-scale system are dressed and a few of valuable solutions are provided. The demonstration of this model a practical system with more than 2000 busbars shows its effectiveness. The obtained charges, diversifying greatly in amount, are able send economic cost-effective signals to prospective network users to influence their connections.

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VIII. Biographies

Chenghong Gu was born in Anhui province, China. He received his Master degree in electrical engineering from Shanghai Jiaotong University, Shanghai, China, in 2007. Now, he is a PhD student with University of Bath, U.K. His major research is in the area of power system economics and planning.

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Lihong Gu was born in Anhui Province in China, on August 7, 1981. He obtained M.Eng. degree in electrical engineering from Shanghai Jiaotong University. He is currently working as a Ph.D. candidate in Electrical Engineering Department of Shanghai Jiaotong University and CEPRI. His research interests include power system stability and wide area damping control.

Long-run Incremental Cost Pricing Considering Uncertain Future Load Growth

Chenghong Gu, and Furong Li, *Member IEEE*

Abstract-- **The importance of efficient and effective charging methodologies to regulatory authorities has resulted in a significant amount of research into methods for deriving economic charges. The majority of the previous work is however limited on the assumption that a given future scenario or a fixed load growth rate, and the fundamental problem of uncertain future load growth rates in charging methodologies imposes great difficulties on precise assessing of charges. In this paper, a novel methodology of evaluating long-run incremental charges with uncertain load growth rate is proposed to handle the uncertainty of load growth rate. Fuzzy logic concept is utilized here to model uncertain load growth rate, and then it is incorporated with long-run incremental cost (LRIC) methodology to calculate charges. The membership functions of years which take circuit to be fully loaded and LRIC charges are deduced by employing the theory of fuzzy extension method. A simple example is given to testify the proposed concept and some important conclusion are presented at last. It is found that compared with original LRIC method new method considering fuzzy load growth rate can effectively model uncertain instinct of load growth rate.**

Index Terms-- **Long-run incremental cost pricing, Network charges, Load growth rate, Fuzzy logic**

I. INRODUCTION

Network charges are charges against generators, large industrial consumers, and suppliers for their use of a network. Methodologies used for setting network charges needs to recover the costs of capital, operation, and maintenance of a network and provide forward-looking, economically efficient messages for both customers and power companies [1-2].

In providing forward-looking and efficient economic message, it is essential that network charges reflect the cost/benefits that new network users impose on the network, i.e. they should discriminate between network users who incur additional operating costs or network reinforcement and expansion, and those who reduce or delay otherwise needed network upgrades. It is for this reason that the concept of incremental charging methodologies was introduced to overcome the drawback. Short-run incremental cost (SRIC) or marginal cost (SRMC) pricing approaches are concerned with the additional operating cost typically resulting from congestions and constraints [3-4]. Long-run incremental cost (LRIC) pricing approaches are concerned with incremental network cost as well as incremental operational costs [5-12].

Developing a LRIC pricing model has been viewed as a formidable task [5-10]. Most existing approaches to long-run pricing require a least-cost future network planning to work out network increment cost with nodal demand/generation increment. It is impractical to evaluate the cost to network with injection at every single node of a network, therefore most long-run cost pricing methods evaluate the incremental network cost associated with projected demand/generation pattern and subsequently allocate the cost to new (and existing) customers. This approach has several drawbacks: 1) they are passive, reacting to a set of projected patterns of future generation and demand, rather than proactively influence the patterns of future generation/demand through economic incentives; 2) the approaches require the knowledge of future generation/demand, while this knowledge is far from certain in a competitive environment and any projected pattern of generation and demand could prove very different in the outturn.

In 2007, Dr Li and Mr. Tolley proposed a novel approach to calculate LRIC in network charges [2]. The methodology seeks to reflect the influence on the advancement or deferral of future investment in network components as a result of a 1MW injection or withdrawal of generation or load at each study node. Compared with existing long-run incremental charge pricing approaches, the proposed approach produces forward-looking charges that reflect both the extent of the network needed to service the generation or load, and the degree to which that network is utilized [13-14].

The basic LRIC charging model works on the assumption that the load growth rate is fixed into the future. Using an underlining load growth rate, the future reinforcement and its timing can be estimated and translated into present value of future reinforcement. In practice, it is however not easy to predict future load growth rates, because they can be affected by many uncertain factors such as economy, policies, regulations and markets. The impact to LRIC charges under different load growth rates can be significant, and such impact can affect the revenue recovery for utilities as well as customers' satisfaction [15-16]. Having said the above, for developed countries, the load growth has already saturated and becomes relatively steady, it is less likely for load growth rates to have huge variations over long term. But for medium developing countries, load growth rates can vary considerably with time, and this is the subject that the paper aims to address.

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In 1965, Mr. Zadeh introduced the concept of fuzzy sets as a mathematical means of describing vagueness in linguistics to treat some uncertain conceptions in reality [17]. A fuzzy set is a generalization of an ordinary set in that it allows the degree of membership for each element to range between 0 and 1. The biggest difference between crisp and fuzzy sets is that crisp sets always have unique membership functions, whereas fuzzy set has an infinite number of membership functions [18]. To date, in power system area, some fuzzy methodologies have been developed to model the uncertainty of load and load growth with fuzzy theories to capture their inherent uncertainties into the future [19-21]. This model can i) effectively reflect the uncertain characteristics of load, ii) make it easier to account for future load and load growth in system planning.

In this paper, a novel fuzzy approach in calculating long-run incremental charges with uncertain load growth rates is proposed. Fuzzy load growth rate model is introduced and incorporated with original LRIC method based on the instinct of load and the characteristics of system. According to the theory of fuzzy extension method, namely vertex method, the fuzzy load growth is mapped into fuzzy LRIC charges through an intermediate variable – fuzzy time to reinforce. The concept of fuzzy LRIC pricing is demonstrated on a simple network, illustrating its effectiveness in dealing with uncertain load growth.

The rest of the paper is organized as follows: Section II introduces fuzzy load growth rate model. Section III gives a simple introduction to LRIC charging methodology. In section IV a LRIC methodology with fuzzy load growth rate is presented. Section V provides a small test system to demonstrate the fuzzy LRIC pricing concept. Finally, the conclusions are drawn in Section VI.

II. Fuzzy Load Growth Rate Model

Supposing initially load amount is L_0 with a load growth rate r, the load amount in year n can be calculated using

$$L_n = L_0 \cdot (1+r)^n \tag{1}$$

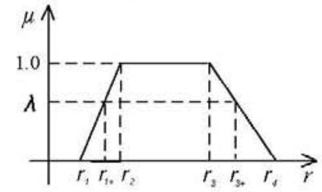


Fig. 1. Fuzzy load growth rate model

Load growth rates can be described using fuzzy set theory to translate propositions like "*load growth rate might be between r_1 and r_4, my confidence in different growth rates varies from 0 to 1 as shown in figure 1*". Unlike crisp load growth rate which represent load growth rate with a single constant value, the fuzzy modelling method can capture the confidence level associated with different load growth rates, thus providing better assessment in future reinforcement, leading to more acceptable network charges. As shown in figure 1, load growth rate may occur any where between r_1 and r_4, however, it is most likely to occur between r_2 and r_3, less likely to occur between r_1 and r_2, and r_3 and r_4. In the area out of r_1- r_4, load growth rate definitely not occurs.

III. Long-run Incremental Cost Charging Model

For network components that are affected by the injection there will be a cost associated with accelerating the investment, or a benefit associated with its deferral. Depending upon the magnitude of the reinforcement cost and the discount rate chosen, the present value of the cost for each affected component can be calculated. The long-run incremental cost is the accumulation of the present values of the cost of all affected network components in supporting a nodal injection or withdrawal. It has the following implementation steps [2].

A. *Determine when investment will occur in the future*

If a circuit l has a capacity of C_l, supporting a power flow of D_l, then n_l is the number of years it takes D_l to grow to C_l for a given load growth rate r

$$C_l = D_l \cdot (1+r)^{n_l} \tag{2}$$

Rearranging equation (2) and taking the logarithm of it gives the value of n_l

$$f(r) = n_l = \frac{\log C_l - \log D_l}{\log(1+r)} \tag{3}$$

Assume that investment will occur in n years when the circuit utilisation reaches C_l. If a discount rate of d is chosen, then the present value of future investment in n_l years will be

$$PV_l = \frac{Asset_l}{(1+d)^{n_l}} \tag{4}$$

Where, $Asset_l$ is the duplicated asset cost.

B. *Cost associated with ΔP_l incremental addition*

If the power flow change along line l is ΔP_l as a result of 1MW injection, which in turn brings forward future investment from year n_l to year n_{lne}

$$C_l = (D_l + \Delta P_l) \cdot (1+r)^{n_{lnew}} \tag{5}$$

Equation (5) will lead to the new investment horizon $n_{l\,new}$

$$h(r) = n_{lnew} = \frac{\log C_l - \log(D_l + \Delta P_l)}{\log(1+r)} \tag{6}$$

This in turn affects the present value of the investment

$$PV_l = \frac{Asset_l}{(1+d)^{n_{lnew}}} \tag{7}$$

The change in present value as a result of investment brought forward by 1MW injection will be

$$g(r) = \Delta PV_l = PV_{lnew} - PV_l \tag{8}$$

Cost for circuit l will be annuitized change in present value of future investment horizon as a result of 1MW injection

$$IC_l = \Delta PV_l \cdot annuityfactor \tag{9}$$

C. *Long-run incremental cost*

Long-run incremental cost to support node N will be the summation of charges over all circuits, given by:

$$LRIC_N = \frac{\sum_l \Delta IC_l}{\Delta P_{In}} \qquad (10)$$

Where, ΔIC_l is the change in unit cost as a result of 1MW injection given by equation (9). ΔP_{In} is the power injection at node N, and assume it is 1MW.

IV. LRIC INCORPORATING FUZZY LOAD GROWTH RATE

This section presents mathematical formulations for LRIC methodology incorporating fuzzy load grow rate.

A. Fuzzy extension method

Vertex method, which is developed by Dong and Shah [22], is utilized to extend principle for continuous-valued fuzzy variables. This method is based on a combination of the λ–cut concept and standard interval analysis. The Vertex method consists of the following steps.

a) Any continuous membership function is represented by a continuous sweep of λ–cut intervals from $\lambda=0^+$ to $\lambda=1$;

b) For fuzzy sets $\underline{A}$ and $\underline{B}$, suppose that a single-input mapping is given by $y=f(x)$, which is extended for fuzzy sets, or $\underline{B} = f(\underline{A})$ and the decomposition of $\underline{A}$ into a series of λ–cut intervals is desired, say I_λ.

When the function $f(x)$ is continuous and monotonic with $I_\lambda=[b, d]$, the interval representing $\underline{B}$ at a certain value of λ, says B_λ, can be obtained by

$$B_\lambda = f(I_\lambda) = [\min(f(a), f(b)), \max(f(a), f(b))] \qquad (11)$$

B. Membership functions of n_l and n_{lnew}

From equation (3), taking derivative of n_l with respect to load growth rate, r, gives the following equation

$$\frac{dn_l}{dr} = (\log C_l - \log D_l) \cdot \frac{1}{1+r} \cdot \left(-\frac{1}{(\log(1+r))^2} \right) \qquad (12)$$

Similarly, taking derivative of n_{lnew} with respect to r, following equation can be obtained

$$\frac{dn_{lnew}}{dr} = (\log C_l - \log(D_l + \Delta P_l)) \cdot \frac{1}{1+r} \cdot \left(-\frac{1}{(\log(1+r))^2} \right) \qquad (13)$$

From equation (8), it can be found that ΔPV is a function of n_l and n_{lnew}. Obviously, it can be seen from (12) and (13) that both n_l and n_{lnew} new are monotonic and decreasing functions with regarding to r. The membership functions of n_l and n_{lnew} with respect to fuzzy load growth model sketched in figure 1, are calculated with vertex method as following.

a) In case of $\lambda=0^+$, $I_{0+}=[r_1, r_4]$

$$B_{0+} = [\min(f(r_1), f(r_4)), \max(f(r_1), f(r_4))] \qquad (14)$$

b) In case of $\lambda=\lambda_m$, $I_{\lambda m}=[r_{1+}, r_{3+}]$

$$B_{\lambda_m} = [\min(f(r_{1+}), f(r_{3+})), \max(f(r_{1+}), f(r_{3+}))] \qquad (15)$$

c) In case of $\lambda=1$, $I_1=[r_2, r_3]$

$$B_1 = [\min(f(r_2), f(r_3)), \max(f(r_2), f(r_3))] \qquad (16)$$

A complete λ-cut representation can be obtained by repeating step (b) for different values of λ. The same method can be utilized to get membership function of n_{lnew}.

C. Membership functions of LRIC charge

Similarly, membership function of LRIC charges can also be obtained using vertex method. The derivatives of ΔPV_l with respect to load growth rate r is

$$\frac{d(\Delta PV_l)}{dr} = Asset_l \times \ln\left(\frac{1}{(1+d)}\right) \times \left(\frac{1}{(1+d)^{n_{lnew}}} - \frac{1}{(1+d)^{n_l}} \right) \qquad (17)$$

In this case, extreme points might exit within the region of the membership function. Fortunately, this can be determined using a derivative of the function with respect to load growth rate r. if the relating load growth rate is r^*, that is

$$\frac{d(\Delta PV_l)}{dr} = g'(r^*) = 0 \qquad (18)$$

a) In case of $\lambda=0^+$, $I_{0+}=[r_1, r_4]$

$$B_{0+} = [\min(g(r_1), g(r_4), g(r^*)), \max(g(r_1), g(r_4), g(r^*))] \qquad (19)$$

b) In case of $\lambda=\lambda_m$, $I_{\lambda m}=[r_{1+}, r_{3+}]$

$$B_{\lambda_m} = [\min(g(r_{1+}), g(r_{3+}), g(r^*)), \max(g(r_{1+}), g(r_{3+}), g(r^*))] \qquad (20)$$

c) In case of $\lambda=1$, $I_1=[r_2, r_3]$

$$B_1 = [\min(g(r_2), g(r_3), g(r^*)), \max(g(r_2), g(r_3), g(r^*))] \qquad (21)$$

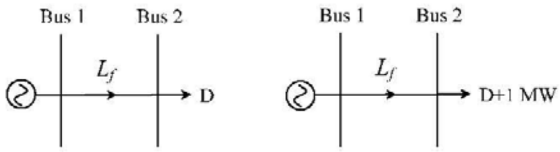
A complete λ-cut representation of the solution can be computed by repeating step (b) for different values of λ.

V. A CASE STUDY AND DISCUSSION

Our concept is testified using a two-busbar simple network given in figure 2[2].

A. Test System Data

The circuit rating of L_f is 45MW after security redundancy and its cost is £236,760/yr. The annuity cost is based on 6.9% discount rate over 40 years life span, and this leads to the circuit total cost as £3,193,400. In this example, five λ-cut situations are considered, showed in figure 3, and the corresponding load growth rates are also provided in table 1.



(a) (b)

Fig. 2. (a) Origianl network (b) Network with1 MW increment

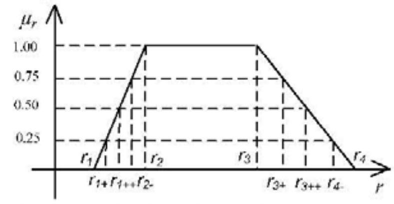


Fig.3. Fuzzy load growth rate of the test system

TABLE.1 FIVE CUTS AND CORRESPONDING LOAD GROWTH RATES

λ =0	λ =0.25	λ =0.50	λ =0.75	λ =1
r_1=0.013	r_{1+}=0.01325	r_{1++}=0.0135	r_{2-}=0.01375	r_2=0.014
r_4=0.018	r_{3+}=0.016	r_{3++}=0.017	r_{4-}=0.0175	r_3=0.016

B. Results and Discussions

Three indices are calculated: time horizon to reinforcement (HtR), time horizon after 1 MW addition (HaA), and annual charge (AC), and results are given in figure 5 and table 2.

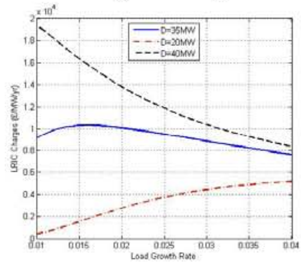


Fig. 4. Variations of LRIC charges with respect to D

In the process of deducing membership functions of LRIC charges, different load level would give birth to quite different shapes of membership functions. Figure 4 presents the changes of LRIC charges with respect to the increase of load growth rate in three scenarios. It is apparent that when D=20MW, charges increase steadily with the rise of load growth rate. While, in case of D=40MW, LRIC charges decrease steadily with respect to the increase of load growth rate. The case of D=35MW gives a quite different shape of characteristic line compared former ones. It is noted that charges increase steadily when load growth rate becomes big and after a peak point, charges drop gradually. Generally, it is found that charges of heavily loaded circuit are constantly higher than lightly loaded circuits.

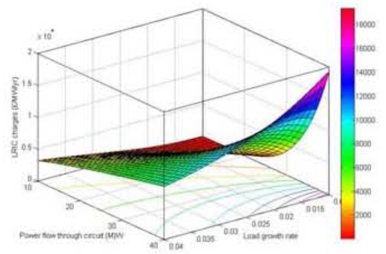
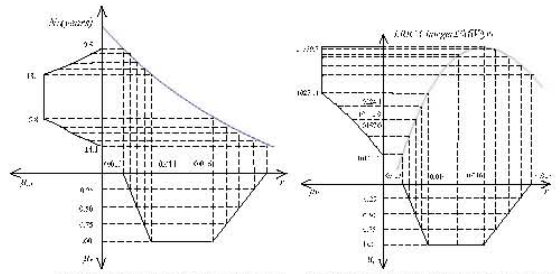


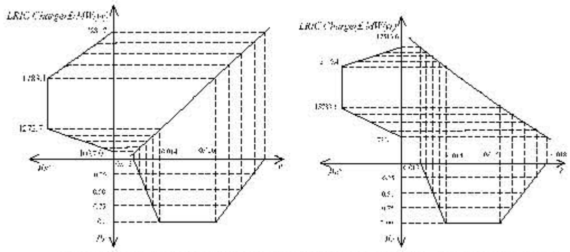
Fig.5. Changes of LRIC charges in different cases

A 3-D image in figure 5 generally indicates how LRIC charges change with respect to circuit loading level and load growth rates. This figure shows that functions of LRIC charges are non-monotonic. Both load growth rate and circuit carrying power influence LRIC charges to a great extent.

Four charts in figure 6 represent membership functions of years to reinforce and LRIC charges under different loading level with respect to fuzzy load model. (a) is the membership function profile of n_l in the case of D=35MW. It can be seen that, if load growth rates range between 0.013 and 0.018, n_l changes from minimal value 14.1 to maximum value 19.5. The degree of membership of n_l grows gradually between 14.1and 15.8, and the values of n_l between 15.8 and 18.1 have the biggest degree of membership 1.0. This figure gives us a clear map of how load growth rates influence n_l.



(a) D=35 Membership of years (b) D=35 Membership of charges



(c) D=20 Membership of charges(d) D=40 Membership of charges

Fig.6 Membership functions under different situations.

Figures (b), (c), and (d) depict the fuzzy membership functions of LRIC charges when D=35MW, D=20MW, and

TABLE.2 LRIC CHARGES IN DIFFERENT SITUATIONS

	D=20MW			D=35MW			D=40MW		
Load Growth Rate	HtR (years)	HaA (years)	AC (£/MW)	HtR (years)	HaA (years)	AC (£/MW)	HtR (years)	HaA (years)	AC (£/MW)
r_1	62.8	59.0	1027.9	19.5	17.3	10116.3	9.119	7.2	17513.6
r_{1+}	61.6	57.9	1088.3	19.1	16.9	10157.0	8.9	7.1	17361.3
r_{1++}	60.5	56.8	1149.5	18.7	16.6	10192.9	8.7	6.9	17209.8
r_{2-}	59.4	55.8	1211.3	18.4	16.3	10224.1	8.6	6.8	17059.5
r_2	58.3	54.8	1273.7	18.1	16.1	10251.1	8.5	6.7	16910.4
r_3	51.1	48.0	1783.1	15.8	14.1	10339.7	7.4	5.9	15783.3
r_{3+}	49.6	46.6	1908.2	15.4	13.6	10333.7	7.2	5.7	15499.9
r_{3++}	48.1	45.2	2034.7	14.9	13.2	10319.1	7.0	5.5	15237.3
r_{4-}	46.7	43.9	2158.4	14.5	12.9	10296.7	6.7	5.3	14981.3
r_4	45.5	42.7	2281.7	14.1	12.5	10267.7	6.6	5.2	14732.1

D=40MW respectively. As for (b), LRIC charges increase from 10,116.3(£/MW/yr) with degree of membership of 0 to 10,251.1(£/MW/yr) with degree of membership of 1. This section is followed by a straight line, which means charges increase synchronously with regarding to load growth rate to 10,339.7(£/MW/yr). The straight line indicates that during this sector, the degree of membership of is constant 1. The charges are dominated by degree of membership of 1.0 when the load growth rate reaches 0.014, because charges have a peak in this sector with regard to a load growth rate of 0.016. Figures (c) and (d) give quite similar membership functions of charges with respect to the given fuzzy load growth rates, but the biggest LRIC charges of (c) appear when load growth rates are quite large and the biggest LRIC charges for (d) happens when load growth rates are small. Figure 6 gives quite different shape of charge membership functions due to the fact that function characteristics of these three cases with respect to load growth rates are quite different.

VI. Conclusions

Uncertainty of load growth rate imposes great difficulties on LRIC charge calculation methodologies. In this paper, a novel methodology of evaluating long-run incremental charges with fuzzy load growth rate is proposed to handle the uncertain characteristics of load growth rate and fuzzy load growth rate model is introduced. Thereafter, the model is incorporated with LRIC methodology. A simple example is utilized here to demonstrate our concept. It is apparent that LRIC method with fuzzy load growth rate can effectively model uncertain nature of load growth rate. Unlike crisp model, this fuzzy model gives a range of LRIC charges with regard to the fuzzy model of load growth rate. Generally, fuzzy representations of years to reinforce and LRIC charges represent range values of years to reinforce and charges and their corresponding degree of membership, while deterministic model only provide a section of the whole load growth rate range. If load growth rate is difficult to determine and only some fuzzy characteristics can be captured, this fuzzy model is an effective tool for evaluation. While our concept is only tested with a simple example, in the future we are going to extend our concept to large-scale system.

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VIII. Biographies

Chenghong Gu was born in Anhui province, China. He received his Master degree in electrical engineering from Shanghai Jiao Tong University, Shanghai, China, in 2007. Now, he is a PhD student with University of Bath, UK. His major research is in the area of power system reliability pricing and long-run incremental cost charging

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SENSITIVITY ANALYSIS OF LONG-RUN INCREMENTAL CHARGE BASED ON ANALYTICAL APPROACH

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ABSTRACT

The long-run incremental cost (LRIC) pricing model developed by University of Bath (U.K.) reflects the accumulated impacts to the long-term network development cost in supporting a nodal injection or withdrawal, represented as the difference in present values of future cost with and without the nodal perturbation. Those differences are generally calculated through iterative simulations. In this paper, the impact to the long-run development cost is represented through an analytical approach. The relationships between nodal injection, power flow changes along all circuits with respect to load injection, the resultant time to reinforce and final charges are analyzed based on Jacobian matrix obtained in power flow. Equations representing the sensitivities of present value of each circuit, years to reinforce and changes to years to reinforce with respect to a very small nodal increment are employed to deduce the relationships between nodal injections and nodal charges. The Resultant charges from respective simulation and sensitivity approaches are compared and contrasted for a practical system with different load injections, load growth rates, and differing loading level conditions.

1. INTRODUCTION

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Network charges are charges against generators, large consumers, and suppliers for their use of a network. Methodologies used for setting network charges need to recover the costs of capital, operation, and maintenance of a network and provide forward-looking, economically efficient messages for both customers and power companies[1]. In order to provide efficient and effective economic message, it is essential that network charges reflect the costs/benefits that new network users impose on network. It is for this reason that the concept of incremental charging methodologies was introduced to reflect the cost to network operation and development from new generation and demand connection [1-5]. Long-run incremental cost (LRIC) pricing approaches focuses on incremental network cost as well as incremental operational costs.

Developing a LRIC pricing model has been viewed as a formidable task [1-6]. Most existing approaches to long-run pricing require a least-cost future network planning to work out network incremental cost with nodal demand/generation increment. However, it is impractical to evaluate the cost to network with injection at every single node of a network. Li and Tolley presented the first paper that directly link the long-term network development cost with nodal increment [1]. The proposed approach makes use of the unused capacity of an exiting network to reflect the cost of advancing or deferring future investment consequent upon the addition of generation or load at each study node on a distribution network[5]. The methodology seeks to reflect the influence on the advancement or deferral of future investment in network components as a result of a 1MW injection or withdrawal of generation or load at each study node. This pricing system is demonstrated its benefit through a study commissioned by Ofgem (Office of Gas and Electricity Market, U.K.) in 2005, suggesting a cost saving in the order to £200m can be made if all distribution network operators (DNOs) in Great Britain could move to the LRIC pricing [7].

The simulation approach to LRIC charges requires running power flow at each node and contrasts the power flows with and without the nodal increment. It can reflect the extent of impact on LRIC charges from a nodal injection. The downside is that it takes much longer time to calculate charges, especially when the system is large. The computational time rises exponentially with the number of nodes in the system. The analytical approach calculates charges from the analytical analyses derived from the sensitivity analyses. The analyses use equations representing the sensitivity of present value of each circuit with respect to a very small nodal increment. If the increment is sufficiently small in the simulation, there should not be too many differences between the two approaches.

In this paper, equations representing the sensitivity of present value of each circuit, years to reinforce, and new years to reinforce with respect to a very small nodal increment are employed to deduce the relationships of nodal injections and nodal charges. Based on Jacobian matrix utilized in power flow, the relationships between nodal injection and state variables (nodal voltage, nodal angles) can be obtained. Thereafter, power flow changes along all circuits with respect to load injection are examined. Therefore, we can acquire how a tiny load injection at different load points influences LRIC charges. Finally, results obtained from simulation and analytical sensitivity analysis with different load injections, load growth rates, and differing loading levels are compared and analyzed.

2. LONG-RUN INCREMENTAL COST MODEL

For network components that are affected by a nodal injection, there will be a cost associated with accelerating the investment, or a benefit associated with its deferral. Depending upon the magnitude of the reinforcement cost and the discount rate chosen, LRIC charges are represented as the present value of the future reinforcement cost for each affected component. LRIC has the following implementation steps[1].

A. Present value of future investment

If a circuit l has a capacity of C_l, supporting a power flow of D_l, then the number of years it takes to grow from D_l to C_l for a given load growth rate r can be determined with

$$C_l = D_l \cdot (1+r)^{n_l} \quad (1)$$

Where, n_l is the number of years taking D_l to C_l.

Rearranging equation (1) and taking the logarithm of it gives the value of n_l

$$f(r) = n_l = \frac{\log C_l - \log D_l}{\log(1+r)} \quad (2)$$

Assume that investment will occur in n_l years when the circuit utilization reaches C_l. If a discount rate of d is chosen, then the present value of future investment in n_l years will be

$$PV_l = \frac{Asset_l}{(1+r)^{n_l}} \quad (3)$$

Where $Asset_l$ is the duplicated asset cost.

B. Cost associated with ΔP_l increment

If the power flow change along line l is ΔP_l as a result of 1MW injection, which in turn brought forward future investment from year n_l to year n_{lnew}

$$C_l = (D_l + \Delta P_l) \cdot (1+r)^{n_{lnew}} \quad (4)$$

Equation (4) will lead to the new investment horizon $n_{l\,new}$

$$h(r) = n_{lnew} = \frac{\log C_l - \log(D_l + \Delta P_l)}{\log(1+r)} \quad (5)$$

This in turn affects the present value of the investment,

$$PV_{lnew} = \frac{Asset_l}{(1+r)^{n_{lnew}}} \quad (6)$$

The change in present value as a result of investment brought forward by 1MW injection will be given by

$$g(r) = \Delta PV_l = Asset_l \cdot \left(\frac{1}{(1+d)^{n_{lnew}}} - \frac{1}{(1+d)^{n_l}} \right) \quad (7)$$

The long-run incremental cost for circuit l will be annuitized change in present value of future investment horizon as a result of 1MW injection

$$LRIC_l = \Delta PV_l \times annuityfactor \quad (8)$$

C. Long-run incremental cost

LRIC charges to support node N will be the summation of LRIC charges over all circuits, given by

$$LRIC_N = \frac{\sum_l \Delta IC_l}{\Delta P_{In}} \quad (9)$$

Where, ΔIC_l is the change in unit cost as a result of 1MW injection, given by equation (9); ΔP_{In} is the power injection at node N, here we have assumed 1MW.

3. SENSITIVITY ANALYSIS MODEL

Power flow analysis model is typically represented by equation (10) and solved by Newton-Raphson method. If a small injection of generation or demand is given, the influence of that injection on system voltage multitudes and angles can be derived by making use of the linearized equation (10)

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial \theta} & \frac{\partial P}{\partial V} \\ \frac{\partial Q}{\partial \theta} & \frac{\partial Q}{\partial V} \end{bmatrix} \begin{bmatrix} \Delta \theta \\ \Delta V \end{bmatrix} = [J] \begin{bmatrix} \Delta \theta \\ \Delta V \end{bmatrix} \quad (10)$$

Equation (11) represents the active power flow along a circuit from bus i to bus j.

$$P_{ij} = V_i^2 G_{ij} - V_i V_j (G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}) \quad (11)$$

Supposing that a tiny active power load D_n is connected to system on a certain point, its effects on P_{ij} can be obtained by using

$$\frac{\partial P_{ij}}{\partial D_n} = \frac{\partial P_{ij}}{\partial V_i}\frac{\partial V_i}{\partial D_n} + \frac{\partial P_{ij}}{\partial V_j}\frac{\partial V_j}{\partial D_n} + \frac{\partial P_{ij}}{\partial \theta_i}\frac{\partial \theta}{\partial D_n} + \frac{\partial P_{ij}}{\partial \theta_j}\frac{\partial \theta_j}{\partial D_n} \quad (12)$$

Where, $\frac{\partial P_{ij}}{\partial V_i}$, $\frac{\partial P_{ij}}{\partial V_j}$, $\frac{\partial P_{ij}}{\partial \theta_i}$ and $\frac{\partial P_{ij}}{\partial \theta_j}$ can be acquired from equation (11) by calculating its derivates of V_i, V_j, θ_i, θ_j. Others are elements of Jacobian matrix, and they can easily be obtained from the last iteration of power flow.

The equation represents the sensitivity of present value with respect to nodal increment comprises of the sensitivity with respect to time to reinforce, of time to reinforce to circuit power flow and of circuit power to nodal increment, and the equation is shown below

$$\frac{\partial PV_l}{\partial D_n} = \frac{\partial PV_l}{\partial n_l} \times \frac{\partial n_l}{\partial P_l} \times \frac{\partial P_l}{\partial D_n} \quad (13)$$

Where, D_n is the nodal increment, P_l is the power flow through a circuit with linked by two nodes i and j. $P_{l,max}$ is the maximum allowed power flow through the circuit, n_l is the time to reinforce circuit l and PV_l is the present value of future reinforcement for circuit l.

4. COMPARISON AT A GSP AREA

In this section, the sensitivity and the simulation methods are compared at a small GSP area, and the operating condition is taken as its winter peak. The system consists of 15 bus bars, 11 circuits, 10 transformers, 7 loads and one generator. The rationale in comparing the two methods on a practical system is that a nodal increment is likely to impact many circuits in the network, if each circuit has some mismatch between the two approaches, its aggregated total mismatches could be significant. The comparisons are carried out for the GSP area under two conditions: i) under different underlying growth rates – 0.5%, 1% and 5%, ii) under differing loading conditions.

A. Comparison of LRIC charges on the GSP - base loading case

Table 1 summarizes differences between the simulation and the sensitivity approach. For the simulation approach, an injection of 1MW is used to assess the nodal incremental effect to the present value of future reinforcement. Figures 1-4 illustrate the differences in LRIC charges graphically.

Table 1. Comparison of LRIC Charges from Sensitivity and Simulation Methods under Different Load Growth Rates (£/Kw/yr)

Bus No.	growth Rate=0.5%		LGR=1%		LGR=5%	
	Sens.	Simul.	Sens.	Simul.	Sens.	Simul.
1001	2.57	3.28	3.82	4.265	5.84	5.886
1002	0.01	0.014	0.546	0.607	4.39	4.419
1003	13.62	15.41	19.06	20.21	10.10	10.14
1004	13.01	14.65	17.61	18.61	8.997	9.04
1005	0.75	0.965	1.75	1.963	1.275	1.285
1006	12.90	14.51	17.18	18.16	6.66	6.698
1007	0.753	0.965	1.752	1.963	1.275	1.285
1009	0	0	0.097	0.122	10.02	10.16
1010	0	0	0.019	0.025	5.974	6.116
1011	0	0.001	0.16	0.245	12.61	12.94
1012	0	0.001	0.157	0.241	11.14	11.43
1013	0	0	0	0	1.961	2.053
1014	0	0	0	0	1.15	1.242
1015	0	0	0	0	2.121	2.3

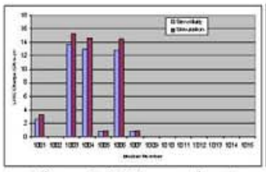

Figure 1. 0.5% growth rate

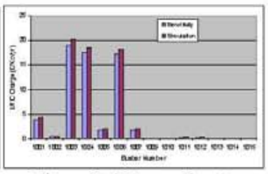

Figure 2. 1% growth rate

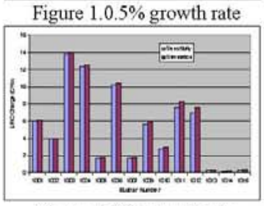

Figure 3. 3% growth rate

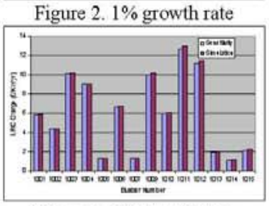

Figure 4. 5% growth rate

A similar trend can be detected from the table and figures: when the growth rate is low, the difference in LRIC charges from the two approaches is larger, when the growth rate is high, the charges differ slightly. Also can be observed is that nodes 1009-1015 are supported by lightly loaded circuits, their charges are close to 0 for low load growth rates, as the growth rates increase from 1% to 5%, charges have increased dramatically. In comparison, nodes 1003-1006 are supported by heavily utilized circuits, their charges decrease as the growth rates increasing.

B. Comparison of LRIC charges on the GSP with higher loading levels-20% scaling

In this study, all loads in the system are scaled up by 20%, thus increasing all circuits' utilization by 20%. Table 2 summarizes the LRIC charges from the two approaches for 0.5%, 1%, 3% and 5% load growth rates. The simulation approach has a 1MW injection.

Table 2. Comparison of LRIC Charges from Sensitivity and Simulation Methods under Different Load Growth Rates (£/Kw/yr)

Bus No.	LGR=0.5%		LGR=1%		LGR=5%	
	Sens.	Simul.	Sens.	Simul.	Sens.	Simul.
1001	27.7	33.88	11.43	12.52	6.25	6.29
1002	0.12	0.14	1.61	1.757	4.68	4.70
1003	148.55	164.43	57.35	60.19	10.83	10.87
1004	141.34	155.81	52.76	55.21	9.62	9.66
1005	6.55	8.098	4.894	5.39	1.38	1.38
1006	140.11	154.34	51.47	53.87	7.12	7.16
1007	6.55	8.10	4.89	5.39	1.36	1.38
1009	0.002	0.002	0.32	0.39	11.08	11.21
1010	0	0	0.06	0.076	6.45	6.57
1011	0.003	0.007	0.54	0.78	14.14	14.45
1012	0.003	0.007	0.53	0.77	12.56	12.85
1013	0	0	0	0	2.1	2.18
1014	0	0	0	0	1.23	1.31
1015	0	0	0	0	2.27	2.43

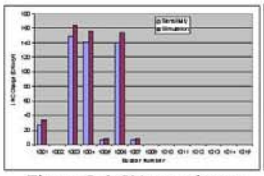

Figure 5. 0.5% growth rate

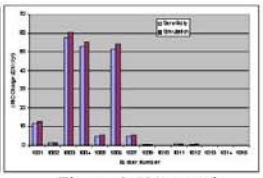

Figure 6. 1% growth

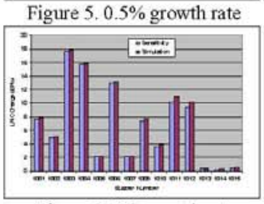

Figure 7. 3% growth rate

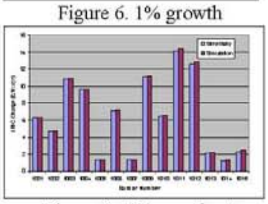

Figure 8. 5% growth rate

For the 20% load scaling, LRIC charges follow the same patterns as for the base case, but the charges are significantly higher than the base case for low load growth rates. Table 3 gives the magnitudes of increment in LRIC charges from the 20% scaling for the two approaches respectively. The magnitudes of increments are similar for both approaches, with lower load growth rates seeing greater increment in charges and greater difference in charges.

Table 3. Magnitudes of Increment in LRIC Charges from 20% load scaling for the Two Methods - Different Load Growth Rates (£/Kw/yr)

Bus No.	LGR=0.5%		LGR=1%		LGR=5%	
	Sens.	Simul.	Sens.	Simul.	Sens.	Simul.
1001	25.13	30.60	7.61	8.26	0.41	0.41
1002	0.11	0.13	1.07	1.15	0.29	0.29
1003	134.93	149.02	38.29	39.98	0.74	0.73
1004	128.33	141.15	35.15	36.60	0.62	0.62
1005	5.79	7.13	3.14	3.43	0.10	0.10
1006	127.21	139.82	34.30	35.72	0.46	0.46
1007	5.79	7.13	3.14	3.43	0.10	0.10

1009	0.00	0.00	0.23	0.27	1.06	1.05
1010	0.00	0.00	0.04	0.05	0.48	0.46
1011	0.00	0.01	0.38	0.53	1.53	1.51
1012	0.00	0.01	0.38	0.53	1.42	1.41
1013	0.00	0.00	0.00	0.00	0.14	0.13
1014	0.00	0.00	0.00	0.00	0.08	0.07
1015	0.00	0.00	0.00	0.00	0.15	0.13

5. CONCLUSIONS

The sensitivity and simulation approach are compared in this paper. In terms of accuracy, the two approaches are similar for a small injection. When the injection becomes large, the discrepancies between the two approaches become apparent. In terms of speed of calculation, the sensitivity approach can save significant computational time especially for large networks. Also because it uses an analytical formula, it is far easier to validate the charging results compared with its simulation counterparts. On the other hand, the many intermediate stages in the simulation approach could offer greater transparencies to potential network users of the reasons for a high or low nodal charge, i.e. either due to greater impact to the circuit utilization, or to the security factor or to a piece of a very expensive equipment or a combination of the three.

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7. BIOGRAPHIES

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