Electricity Market based Demand-side Integration in Smart Grid

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A thesis submitted in fulfilment of the requirements for the degree of Doctor of Philosophy

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Abstract

Demand-side integration (DSI) refers to the overall technical area focused on advancing the efficient and effective use of electricity to support power systems and its customer needs. As smart grid (SG) development continues to transform the passive distribution network to the active network with increasing distributed energy resources (DER), the importance of the electricity distributors also shifts from being the network asset owner to more of the network operator role. To integrate the demand-side of electricity market having diverse DER ownership and varying customer needs and expectations, it is not enough just to rely on nodal price signalling that is based on the wholesale electricity market considering the transmission grid constraints. Instead customer choice, service quality differentiation, fashionable lifestyle choices, innovative technologies and new media methods are important factors of DSI price signalling on the retail market side, alongside the technical features of DERs and the distribution network regulatory policies.

This thesis recognises the role of wholesale nodal prices as a proxy of real-time energy cost, but focuses more on the derivation and modification of the distribution network usage cost considering various DERs. The DSI approaches that have been investigated focus on the three aspects: distributor pricing structure, service quality differentiation and customer comfort with distribution network constraints. To investigate each aspect, the standardised distribution test networks have been modelled, on which the optimisation formulations are solved by the GAMS software and the network parameters are derived from the open-source distribution analysis software of GridLAB-D or OpenDSS. The software MATLAB or Excel VBA has been used to automate the software execution and data transfer.

Firstly to refine the distributor price signalling, the controllable loads and photovoltaic (PV) units have been factored in to the distribution network planning based on the long-run average

incremental costs (LRAIC). The avoided or deferred investment costs of reinforcing the distribution network have been used to determine the amount of discount or rebate payable to the DER owner. For the case of controllable loads, the rebates of offering the loads as controllable become less when more controllable loads are enabled. For the case of PV integration, PV growth has been planned similarly to the peak load growth. When PV penetration level is high, some of the network reinforcement costs need to be attributed to the PV owners. On the other hand, the benefit of PV support infrastructure, such as electricity storage systems (ESS), can be separately recognised.

Secondly, the delivery service quality differentiation is made possible with the advance of SG technologies, such as using controllable loads, distribution automation or ESS. However, it is best to conduct the network planning and operation according to the individual customer needs and aspiration of a highly reliable network. The proposed reliability premium (RP) based on load point reliability indices is the payment adjustment to the normal distribution network tariff, which also reflects the customer reliability preference at a more granular level. The logic behind this is that customers who pay for more RP are expected to receive better network supply quality and higher compensation; while the extra reliability built in to the network by the distributor can also be 'traded' to the wholesale market using automated load control if not desired by the 'free-rider' customers.

Thirdly, to facilitate the role of distributor as the network operator, a DER scheduling approach has been proposed to use the 'time value' of deferrable loads in the objective formulation instead of the typically used monetary terms. The DER scheduling approach recognises the operational benefit of deferrable loads in the system and also the importance of safeguarding customer comfort. The network asset has shown to be fully utilised by operating all the network voltages close to the lower voltage constraints. The scheduling intervals are adjusted to be more granular when closer to the present time but more coarse in the distant future, so that higher time resolution and longer scheduling horizon can both be achieved. The computation performance has been tested for a practically large distribution test network with numerous DER decisions, in which scheduling results have also indicated the possibility of quantifying the individual DER contribution during the final reconciliation process.

Overall, the thesis has led to the discussions on an emerging topic of transactive energy, which is the first of its kind addressing the aspects of New Zealand Electricity Market, power systems and regulatory environment altogether.

Acknowledgements

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Acronym

AAC	:	All aluminium conductor
AAAC	:	All aluminium alloy conductor
AC	:	Alternating current
ACSR	:	Aluminium conductor steel reinforced
Al	:	Aluminium
AMD	:	Anytime maximum demand
AMI	:	Advanced metering infrastructure
ADR	:	Automated demand response
CO_2	:	Carbon dioxide
COM	:	Component object model
CPD	:	Coincident peak demand
CPI	:	Consumer price index
CPU	:	Central processing unit
Cu	:	Copper
DC	:	Direct current
DD	:	Demand dispatch
DER	:	Distributed energy resource
DG	:	Distributed generation
DSM	:	Demand dispatch
DSO	:	Distribution system operator
DR	:	Demand response
DSI	:	Demand-side integration
DSM	:	Demand-side management

DSP	:	Demand-side participation
EA	:	Electricity Authority
EEPS	:	Energy Efficient Portfolio Standard
ESS	:	Energy storage system
EV	:	Electric vehicle
FIR	:	Fast instantaneous reserve
FIT	:	Feed-in-tariff
GAMS	:	Generic Algebraic Modelling System
GDX	:	GAMS Data eXchange
GFN	:	Ground fault neutraliser
GIS	:	Geographic information system
GXP	:	Grid exit point
HEMS	:	Home energy management system
HV	:	High voltage
HVAC	:	Heating ventilating and air-conditioning
ICP	:	Installation control point
ICT	:	Information and communications technology
IEEE	:	The Institute of Electrical and Electronics Engineers
LMP	:	Locational marginal price
LRAIC	:	Long-run average incremental cost
LRIC	:	Long-run incremental cost
LRMC	:	Long-run marginal cost
LV	:	Low voltage
LVRT	:	Low voltage ride through
MINLP	:	Mixed integer non-linear programming
MV	:	Medium voltage
NRS	:	Non responsive schedule
NZ	:	New Zealand
NZEM	:	New Zealand Electricity Market
ODV	:	Optimised deprival valuation
OFGEM	:	Office of the Gas and Electricity Markets
O/H	:	Overhead

OLTC	:	On-load tap changer
PBR	:	Performance based rate-making
PCC	:	Point of common coupling
PEV	:	Plug-in electric vehicle
PHEV	:	Plug-in hybrid electric vehicle
PQ	:	Power quality
PRS	:	Price responsive schedule
PV	:	Photovoltaic
PVC	:	Polyvinyl chloride
PVDG	:	Photovoltaic distributed generation
RAM	:	Random-access memory
RBTS	:	Roy Billinton test system
RIIO	:	Revenue using Incentives to deliver Innovation and Outputs
RMINLP	:	Relaxed mixed integer non-linear programming
RTP	:	Real time pricing
SCADA	:	Supervisory control and data acquisition
SCED	:	Security-constrained economic dispatch
SFT	:	Simultaneous feasibility test
SG	:	Smart grid
SIR	:	Sustained instantaneous reserve
SPD	:	Scheduling pricing dispatch
TCL	:	Thermostatically controlled load
ToU	:	Time of use
U/G	:	Underground
UK	:	United Kingdom
UoS	:	Use of system
US	:	United States
VBA	:	Virtual Basic for Applications
VoLL	:	Value of lost load
vSPD	:	Vectorised scheduling pricing dispatch
WACC	:	Weighted average cost of capital
WITS	:	Wholesale information trading system

Nomenclature

Chapter 3

Sets and Indices:

m,m'	:	bus index, $m, m' \in M$, where M is the total bus number.
j	:	Branch index.
bs	:	Loss segment, $bs \in Nbs$, where Nbs is the total segment number.
k	:	Trade block, $k \in TB$, where TB is the total number of trade blocks.

Constants:

Sb	:	Base MVA.

Parameters:

$Plss_m$	:	Equivalent network loss at bus m (p.u.).
$Bloss_j$	:	Piece-wise linear branch losses (p.u.).
$Ploss'$	:	Calculated AC branch losses (p.u.).
PD_m	:	Load at bus m (p.u.).
$B_{mm'}$	:	The mm'^{th} element of network admittance (susceptance) matrix (p.u.).
$\Theta_{m,m'}$	:	1 if buses m and m' are connected by a branch. 0 otherwise.
B_j	:	Admittance (susceptance) of branch j (p.u.).
$LF_j(bs)$	:	Loss factor.
PGm_k	:	Maximum generation specified in a trade block (p.u.).
GC_k	:	Generation price specified in trade block k (\$).
Bcm	:	Maximum capacity of a branch.
PV_{pen}	:	PV penetration level.
PV_{ave}	:	Average PV output power (kW).
Γ_{ave}	:	Average load apparent power (kVA).

Variables:

PG_m : Generation output at bus m (p.u.).

$BFlow_j$: Real power-flow of branch j (p.u.).

θ'_m : Bus angle (radian).

$\Delta\theta_j$: Bus angle difference (radian).

PC : Total cost in dispatch ($).

Chapter 4

Sets and Indices:

f : Distribution feeder conductor.

p : Feeder conductor type.

s : Feeder conductor size.

Constants:

g : Annual load growth rate.

g' : Projected PV growth rate.

y : The number of years to reinforce (year).

L_I : Peak ampacity margin reserved for load switching (A).

L_V : Limit on voltage drop per unit length of feeder conductor (Volt/km).

L'_V : Limit on voltage rise per unit length of feeder conductor (Volt/km).

w_{peak} : Weighting of TR for conductors that is load-dependent.

w_{ind} : Weighting for poles that is load-independent.

w_{pv} : Weighting of TR to support PV installations.

Parameters:

I_f : Feeder conductor current at peak loads (A).

I'_f : Reverse current flow at a given PV penetration level.

$\Omega_{f,p}$: 1 means the feeder conductor f has type p, 0 otherwise.

$R_{p,s}$: Conductor resistance (Ω/km).

$M_{p,s}$: Feeder conductor ampacity (A).

$C_{p,s}$: Feeder conductor replacement cost data ($000/km).

TL : Total life of the asset (year).

RL : Remaining life of the asset (year).

$ODRC$: Optimised depreciated replacement cost ($/year).

ORC_{pv} : ORC brought forward to the present value (\$/year).

TR : Target distributor revenues to be collected (\$/year).

VP : Volume-based distributor price (\$/kWh).

ES : Total energy served in the year (kWh).

SV : Notional savings achieved by using DERs in planning (\$/year).

$NCPV$: Total installed PV capacity not coincide with peak demand (kWh).

$\Delta NCPV$: Reduced non-coincident PV capacity (kWh).

ΔCPD : Reduced coincident peak demand (kWh).

DEP : Yearly depreciation value of the delayed reinforcement costs (\$/year).

ORC_d : Delayed capital expenditure (\$/year).

RB : Daily rebates due to ΔCPD or $\Delta NCPV$ (\$/kWh).

Variables:

D_f : 1 means feeder f needs reinforcement, 0 otherwise.

$S_{f,s}$: 1 means feeder conductor f is size s, 0 otherwise.

ORC : Notionally optimised replacement costs (\$/year).

Chapter 5

Sets and Indices:

n : Customer or customer's device.

m : Load point or node.

i : Network zone.

j : Network branch.

Constants:

λ : Prescribed system level failure rate per year.

r : Prescribed system level repair time per failure (hour).

AT : Allowed hours of load interruption every year for each load or device (hour).

Parameters:

$RP_{m,n}$: Payment of the reliability premium from customer n at load point m (\$).

$IP_{m,n}$: Interruption payment to customer n at load point m if supply is lost (\$).

DP : Duration payment to customer n at load point m if supply is lost (\$/hour).

$RDT_{m,n}$: Reliability differentiated tariff from customer n at load point m (\$).

$\overline{\lambda_{ij}}$: Total failure rate of zone i branch j.

$\overline{r_{ij}}$: Average repair time of zone i branch j (hour).

P_{prs} : Wholesale market price by responding to reduce the demand (\$/MWh).

P_{ret} : Retail price (\$/MWh).

P_{nrs} : Indicated market price without reducing demand (\$/MWh).

$\Gamma_{m,n}$: Demand metered for customer n at load point m in previous interval (MWh).

λ_m : Failure rate at load point m using the zone-branch technique.

r_m : Repair time per failure at load point m (hour).

Variables:

NB : Net benefit for both energy retailers and distributors (\$).

WS : Wholesale savings (\$).

TPC : Total penalty cost (\$).

DPC : Direct penalty cost (\$).

$K_{m,n}$: 1 if customer or device is controlled in current interval. 0 is uncontrolled.

Γ^{dd} : Exact load reduction has to be maintained as instructed (MWh).

$AT_{m,n}$: Accumulated hour of interruption during the past 365 days (hour).

$AT'_{m,n}$: Modified accumulated hour of interruption on a seasonable basis (hour).

Chapter 6

Sets and Indices:

t : Time interval, $t \in T$, where T is total number of scheduling time intervals.

m : Node, m, m' or $m'' \in M$, where M is total number of network nodes.

n : Device, $n \in N$, where N is total number of DER devices.

w : Device state, $w \in W$, where W is total number of device states.

Constants:

LV^{up} : Upper voltage limit of all nodes (p.u.).

LV^{lo} : Lower voltage limit of all nodes (p.u.).

Parameters:

$\Psi_{n,m}$: 1 if device n is connected to node m. 0 otherwise.

$\Theta_{m,m'}$: Upper triangular matrix having value of 1 if nodes m and m' are connected by a branch. 0 otherwise.

$\Omega_{m,m'}$: Upper triangular matrix having value of 1 if node m' is in the downstream of node m. 0 otherwise.

$Rg_{m,m'}$	:	Upper triangular matrix having value of 1 if the branch that has a voltage regulator. 0 otherwise.
τ_t	:	Actual time duration of time interval t (hour).
T_n^{o}	:	Target temperature.
T_n^{b}	:	Temperature fluctuation band.
t_n^{off}	:	The time it takes for the temperature to move between bands when a device is off.
t_n^{on}	:	The time it takes for the temperature to move between bands when a device is on.
$\Gamma'_{t,m}$	:	Metered load demand at node m over time interval t with duration τ_t (p.u.).
PV_t	:	PV variation factor in time interval t, $PV_t \in [0, 1]$, 1 is full output.
$KF_{m,m'}$	:	Voltage change factor between nodes m and m' (p.u./p.u.).
$LI_{m,m'}$	:	Current limit of a branch between nodes m and m' (p.u.).
$Z_{m,m'}$	:	Linearly approximated branch impedance between nodes m and m' (p.u.).
DT_n	:	DER device type.
$\bar{\Gamma}_{n,w}$	:	Average energy (p.u.) of device n in state w over τ_t.
$\bar{\Gamma}_n^{\text{up}}$	:	Average energy (p.u.) in the highest possible state.
$\bar{\Gamma}_n^{\text{lo}}$	:	Average energy (p.u.) in the lowest possible state.
ET_n	:	Maximum stored energy of device n (hour $\cdot$ p.u.).
EB_n	:	Starting energy required for device n to finish a job cycle (hour $\cdot$ p.u.).
EF_n	:	Incremental device energy over τ_t to compensate for heat dissipation (p.u.).
TB_n	:	Time from device n being registered to device n operation being ended (hour).
$TA_{t,n}$	:	Time available at the end of t beyond which device n must operate (hour).
$TS_{t,n}$	:	Sum of $TA_{t,n}$ from device n being registered to time interval t (hour).
		Variables:
OBJ	:	Objective function.
$\Gamma_{t,n}$	:	Scheduled demand or output over τ_t of device n in time interval t (p.u.).
$E_{t,n}$	:	Energy status of device n at the start of time interval t (hour $\cdot$ p.u.).
$U_{t,m}$	:	Voltage at node m in time interval t (p.u.).

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Extent of contribution by PhD candidate (%)	50

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Name	Nature of Contribution
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Nature of contribution by PhD candidate	Conduct simulation and draft the publication
Extent of contribution by PhD candidate (%)	50%

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and from 'Distributor pricing approaches enabled in smart grid to differentiate delivery service quality'. 2014 ICST EAI Trans. on Energy Web, 14(3): e1. doi: dx.doi.org/10.4108/ew.1.3.e1

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CO-AUTHORS

Name	Nature of Contribution
Nirmal-Kumar C Nair	Revising paper, giving feedback, checking publication (20%)

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Chapter 1

Introduction

The term demand-side integration (DSI) is evolving from the concepts and practices of demand-side management (DSM), demand response (DR) and demand-side participation (DSP). For a vertically integrated electricity industry abroad, DSM reflects the traditional role of a transmission grid operator to manage the grid peak. DR and DSP have become more popular as the electricity infrastructure operation has been restructured and the electricity market was established. However, the focus has still been on facilitating the transmission grid operation.

The smart grid (SG) concept is essentially to develop the smart distribution networks with increased penetration of distributed resources enabled through the information and communications technology (ICT). The distribution networks were traditionally designed to passively deliver power, but they are becoming more active by integrating various types of demand-side resources. The term DSI refers to 'the overall technical area focused on advancing the efficient and effective use of electricity in support of power systems and customer needs [1]'. The emerging trend treats the demand-side of the systems as an integrated entity that is capable of exchanging decisions amongst the demand-side resources themselves as well as communicating to other entities of the electricity power network.

Adding to the mix is the market mechanism, which encourages the efficient use of electricity through price signalling from the wholesale electricity market. However, demand-side resources have a diverse range of ownership and electricity customers have various needs and wants. Looking from the electricity retail market side, customer choice, service differentiation and fashionable lifestyle with innovative technologies may become even more important factors than sale price signalling to influence customer behaviour while using electricity.

Therefore, this thesis titled as ‘electricity market based demand-side integration in smart grid’ explores this emerging new reality with the attributes from the above three areas of advancement.

1.1 Motivation

As one of the earliest electricity markets in the world, the New Zealand Electricity Market (NZEM) implements the security-constrained economic dispatch (SCED) with full locational marginal prices (LMP) or full nodal prices. To integrate the demand-side resources into the wholesale market structure, the system operator now publishes a price-responsive schedule (PRS) and non-responsive schedule (NRS). The demand dispatch (DD) scheme has been introduced to allow users to elect to be dispatchable and follow dispatch instructions similar to the generators, thereby being able to set the market price. Another operational innovation that factors in the heavy reliance on hydro-resource in New Zealand is scarcity pricing, which is designed to provide clearer wholesale pricing signals during supply emergencies and administrative load curtailment so that investments in last resort generation and voluntary demand-side response are encouraged.

In distribution networks, hot-water cylinder control has been widely implemented in New Zealand for peak demand management. The long-run average incremental cost (LRAIC) is the recommended approach by the Electricity Authority (EA) for the core distribution network pricing methodology to reinforce the network. The avoided cost or deferred cost is a prescribed approach for the pricing of distributed generation (DG) connection charge in New Zealand, which is implemented by the distributor after negotiation with the DG owners to realise the network supporting role of DG. In the near future, the distribution networks will integrate a numerous number of renewable photovoltaic (PV) solar panels and electricity storage systems (ESS) . The smart appliances and automated demand response (ADR) will work better with variable pricing. Therefore, the discussions on the distribution network regulatory framework will continue on how the SG technologies can be enabled to achieve greater benefit. Overseas regulation examples in the UK and US have provided some insight that could be applicable in the New Zealand situation. So far, NZ regulation on distribution network investment has helped achieve a relatively higher level of network reliability, but higher costs must be borne by all customers as a result. Recently, a new principle-based distributor pricing methodology has been proposed by the EA, which is closely referred to in this research.

To facilitate retail market competition, the barriers for electricity customers to switch among retailers have been considerably lowered in New Zealand, which is the first step in raising consumer awareness of the available options to actively manage electricity costs. However, residential customers mostly pay a flat rate for electricity with some regions using Time of Use (ToU) rate. Electricity retailers as commercial entities are mainly offering discounts to keep their customer from switching to other retailers, as opposed to designing customised retail products to suit different customers' needs, such as customers' preferred level of service quality or technology support. Therefore, it is arguable as whether undercutting the profit margin in the retail market is healthy and sustainable in the long run. Gradually, as more consumers choose to produce renewable power by themselves, they will become the 'prosumers'. The market share may shift from electricity retailers to electricity service providers, so it is worth considering investing in service-enabling technologies and infrastructure.

Overseas experience and development are important references to demand-side integration (DSI) in New Zealand, but the New Zealand situation needs to be assessed based on its own network characteristics, technology options and policy environment. The proposed DSI framework addresses the current and upcoming challenges of the electricity industry, which also contributes to the DSI experience and facilitates the SG technology adoption in New Zealand and around the world.

1.2 Objective

The objective of this thesis is using network parameters and conventional indices to develop distribution pricing models that fit into the regulatory framework. The objective is interlaced by three layers.

The first layer is the technological, physical or engineering layer, which is to identify, compare and recommend the traditional power system network parameters and the conventional indices from power system analysis, in order to send pricing signals for demand-side integration (DSI) in smart grid (SG).

The second layer is the price, business or economics layer, which is to develop and demonstrate pricing models around distribution networks to optimise network operations and to integrate the retail and wholesale markets.

The third layer is the rule, social or regulatory layer, which is to demonstrate the new economic and pricing model can fit into the current or the possible future regulatory framework by proposing necessary improvements or changes around the distribution network regulation to facilitate SG adoption and transition.

1.3 Scope

Corresponding to each layer in the objective, the scope of activities is defined in three areas respectively.

1.3.1 Engineering layer

The activities in this scope of the thesis are to:

1. Understand technologies and networks by comprehensively reviewing the existing DSI approaches with current technologies and infrastructure for distribution networks, as well as the evolving ones under the new SG paradigm.

2. Investigate mathematical models of DSI by reviewing the simulation of device behaviours, control methods, network flows, network parameters, network indices, simplified optimisation models and the computation requirements.

3. Integrate the models and formulate the constraints by simulation in the standardised test networks to study the physical implications of DSI on the networks, leading to future applications on the large practical networks of New Zealand.

4. Compare and recommend network parameters and indices based on the evolving practice and regulations in the electricity industry, the merits of DSI technologies and approaches, and supporting infrastructure required.

1.3.2 Economics layer

The activities in this scope of the thesis are to:

1. Understand both electricity wholesale and retail markets in terms of the market design, current issues and on-going development of the NZEM and overseas markets.

2. Review the optimisation model of the scheduling, pricing and dispatching (SPD) used in the NZEM and simulate the market using a professional optimisation software.

3. Investigate financial implications of DSI on the electricity market stakeholders by implementation of the proposed DSI approaches.

4. Investigate and develop new DSI pricing models during SG transition by bringing more visibility into distribution network characteristics other than integrating into the wholesale SPD model, as well as addressing the challenges and merits of the new DSI pricing model.

1.3.3 Regulatory layer

The activities in this scope of the thesis are to:

1. Understand the industry regulations, policies and business environment by reviewing the New Zealand distribution network regulatory framework and the contemporary regulatory thinking from overseas.

2. Demonstrate the new economic and pricing model can fit into the current or the possible future regulatory framework by practical or pilot projects if there are opportunities to work with the system operator or to manage the low-voltage networks.

3. Participate in policy submission and consultation by investigating the wider social and economic implications of the new DSI technology and pricing models.

1.4 Structure of dissertation

This thesis has been presented using seven chapters.

Chapter 1 introduces the background of the thesis topic according to the three key phases from the thesis title. The motivation is then explained with the latest development in the wholesale market, distribution networks and retail market of New Zealand. The three layered approaches are discussed to clarify the objectives and scope, which have been completed with reference to corresponding sections of the thesis.

Chapter 2 reviews the literature from the aspects of device modelling, network optimisation, and the regulatory business model. In the device modelling, various types of distributed energy resources (DER) are reviewed, which will be more common as the smart grid (SG) develop. Traditional and contemporary distribution network operation objectives are reviewed in the network part, which then leads to the review of the distributor regulatory framework and the cost allocation methodology.

Chapter 3 serves as a transitional chapter to bridge the following three main chapters. Various stakeholders in the de-regulated electricity market are discussed, focusing on their roles related to the demand-side integration (DSI). The different software integration, standardised distribution test networks, and practical system data are discussed in the methodology section. To complete the loop, the nodal electricity market formulation is at the transmission grid and the modelling issues of the low-voltage (LV) distribution network are the last mile close to the customer end.

Chapter 4, 5 and 6 address all three objectives from different perspectives. Chapter 4 presents the distributor pricing structure for the clear signalling to the various types of DERs, which is modified to accommodate the controllable loads and photovoltaic distributed generation (PVDG).

Chapter 5 proposes the payment of the reliability premium (RP) to the distributor based on the load point reliability indices, which does not only indicate the individual customer' reliability preference explicitly but also factors the load priority in the proposed load control dispatch algorithm for wholesale market saving.

Chapter 6 demonstrates that different types of DERs can be integrated in the SG environment by their availability in real-time. The proposed DER scheduling optimisation for a distributor differs from the existing ones, in which it uses the 'time value' of deferrable demand in the objective formulation instead of the typically used monetary terms. The contribution of the individual DER device can be quantified in the final reconciliation process.

Chapter 7 concludes the thesis and lists the contributions arising during the course of this research. It has identified the future directions to achieve integration of demand-side resources based on the electricity market and SG, which also leads to the emerging research topic of transactive energy.

Chapter 2

Literature Review

This chapter reviews the literature from the aspects of distributed energy resources (DER) modelling and optimisation, the optimal distribution operation and cost allocation methodologies, and the evolving distribution regulatory framework and business environment.

Followed by the three-layered approach to conduct the thesis, the chapter is also organised in three parts, covering the device modelling in Section 2.1, network optimisation in Section 2.2 and regulatory models in Section 2.3.

Chapter 4 refers to the literature review in Section 2.1.2, 2.1.3, 2.2.4 and 2.3, Chapter 5 is associated with Section 2.1.4 and 2.2.3, and Chapter 6 is related to Section 2.1 and 2.2.4.

2.1 Modelling of distributed energy resources

In this section on device modelling, various types of distributed energy resources (DER) are reviewed. In addition to demand response (DR) to wholesale electricity price by large industrial customers, the automated demand response (ADR) is suitable for the medium to large commercial premises. The thermostatically controlled loads (TCL) are controllable loads enabled by small residential customers. Photovoltaic distributed generation (PVDG) can be the large size installed by the utility, medium size installed on-site, or small size installed on the roof-top. Electricity storage systems (ESS) and electric vehicle (EV) will be more commonly distributed across the entire distribution network.

2.1.1 Automated demand response

The following list is the classification of demand response (DR) programs.

- Incentive based programs
  - Classical
    * Direct control
    * Interruptible/curtailable programs
  - Market based
    * Demand bidding
    * Emergency DR
    * Capacity market
    * Ancillary service market
- Price based programs
  - Time of use (TOU)
  - Critical peak pricing
  - Extreme day critical peak pricing
  - Extreme day pricing
  - Real time pricing (RTP)

From US, automated demand response (ADR) involves a communications infrastructure that provides the owner of the system with electronic signals that communicate with the facility's energy management control system to coordinate load reductions at multiple end-uses [2]. In systems where there is no active wholesale market of electricity, ADR can be implemented as classical direct control of residential loads [3] or controllable loads, such as hot-water cylinder control before the NZEM was established in NZ. ADR can also be implemented as interruptible programs for non-residential loads.

In a market based system, ADR can participate in demand bidding and emergency DR, which requires the response time-frame longer than a few minutes [4].ADR can be enabled for ancillary services, such as regulating or backing up the system frequency, but the control and metering requirements are much higher than the ones for demand bidding, and the time-frame of response is in the order of seconds.

ADR can support grid operation and renewable integration, but there have been several technological barriers [2], including lack of advanced metering infrastructure (AMI), lack of cost-effective enabling technologies such as automated home appliances, communication or control equipment, concerns about cost recovery with technological obsolescence and lack of open standards to support interoperability. The OpenADR 'client-server' standard has recently gained some interest to remove the above barriers. There has also been effort to standardise the 'Smart Appliance' interfaces through a regulatory mandate in Australia [5].

2.1.2 Thermostatically controlled loads

Conventional power plants such as steam and nuclear plants have been very slow to ramp up or down their power output, in contrast to the renewable generation that is variable in nature. Thermostatically controlled loads (TCL) can be turned on and off without sacrificing customer comfort, or their duty cycles can be adjusted to control the average demand. The ability of TCL to convert electrical energy and store as thermal energy can provide operational benefits for the grid and network operators to coordinate TCL with variable PV or wind generation, so that the system frequency and balance can be easier to maintain.

The demand of refrigerator loads [6], hot-water loads [7] and PEV charging loads [8] has been modelled and dynamically controlled for the frequency regulation service. These resources can be stochastically modelled as a battery with dissipation [9]. The heating, ventilating and air-conditioning (HVAC) loads are also modelled and evaluated in aggregate [10] for the balancing services. Electric water heaters are controlled to minimise the peak import and export due to PV [11].

2.1.3 Photovoltaic distributed generation

The integration of photovoltaic distributed generation (PVDG) into distribution networks starts to take off and accelerate in many places worldwide. The term 'integration' generally refers to physically connecting the generator to the electricity network at the point of common coupling (PCC), and securely and safely operating the system and controlling the generator output optimally [12]. The concept of hosting capacity for PV penetration in the LV networks is used, which is usually determined by a combination of criteria in terms of voltage, loading, protection, power quality and asset operational duty.

Voltage problems

Distribution network operators are prescribed to manage the voltage within a band no more or no less than a certain percentage of the nominal voltage [13], which is plus or minus 6 percentage points in NZ. Voltage rise problems are caused by downstream PV generation exceeding the loads, so the extra power generated by PV may create reverse power-flow and reverse current along the line. The cause of voltage rise is related to the network impedance, so rural networks may see more voltage rise problems [14]. However, practical NZ experience indicates that suburban networks are more prone to voltage rise problem. As an emerging topic in distribution network operation, it is imperative that the PV inverter control strategies to deal with voltage rise problem are investigated [15] [16].

Since PV output is subject to the passing cloud, voltage fluctuations or phase imbalance may happen if PV installations are clustered. Traditionally, automatic tap changing transformers, line voltage regulators and capacitors can adjust voltages to varying loading conditions, but asset life may be reduced due to the frequent operations and more investment in voltage regulation assets may be required. The autonomous inverter control strategies are used to control the PV output [17], so that the use of tap changers could be minimised.

In some extreme voltage fluctuating conditions when a cluster of PV outputs suddenly drop, it can create a voltage dip [18] that triggers more PV inverters to shut down due to the current inverter setting requirements. Hence, it may lead to more severe transient voltage instability that can false trip more protective devices, which in turn causes widespread voltage collapse.

In terms of power quality, there is also concern that harmonic distortion may be caused by the switching of PV inverter operations, whose severity depends on the topology of LV network, PV number and size, the locations of loads, and the locations of PV installations [19].

Abnormal operations

A PV system with the electronic inverter is different from the traditional synchronous generator or induction machine models, so its fault contributions and fault duties in the pre-fault conditions to withstand faults momentarily before a protective device operates need to be assessed [20].

Currently when the PV inverter does not disconnect for a very short time after the grid is tripped, islanding can happen to continue operating with local load. The anti-islanding requirement prescribes that inverters should be disconnected immediately for residential PV systems [21], but this may be changed to require advanced inverters being capable of the low-voltage-ride-through (LVRT) to provide static and dynamic network support.

Distribution networks consist of overhead lines and underground cables that are multiply grounded, so earth fault currents can be engineered to the desired value by the use of neutral impedance and the zero-sequence impedance is important in the calculation of ground potential rise.

Overall, no major overhaul of the fundamental design methodology will be expected in residential protection or voltage control, but the device settings need to be reviewed as PV penetration level increases [22].

2.1.4 Electricity storage systems and electric vehicles

The electricity storage systems (ESS) are very important distributed resources and electric vehicles (EV) are the upcoming major loads in distribution networks.

The ESS control strategies are assessed in [23] to mitigate the voltage rises through grid simulation and economic evaluation. The benefit of battery storage system in addition to PV inverters is optimised in [24] for the feeder capacity and voltage regulation. Electricity storage systems (ESS) can shift energy discharge to the evening peak, so optimal sizing of the storage capacity needs to be investigated as in [25]. ESS can also support more wind energy generation in distribution networks [26].

The uncontrolled charging of electric vehicles is simulated on a test network of a suburban residential LV feeder in [27]. A distribution circuit load profile is used to determine the household demand limit when scheduling the PEV charging and DR together in [28]. The distribution network congestion is implicitly addressed by managing the PEV charging as a series of packet requests to emulate the random access communication system where a charging request can be either accommodated or denied as in [29].

2.2 Optimal operation of electricity networks

Distribution network operational objectives change from time to time. For distributors and retailers who were or are still a combined entity in many electricity industries around the world, their objectives are to minimise the total operational costs, including energy costs, asset maintenance and network electrical losses. As the market structure was de-regulated, the variable pricing structure has been developed to signal the constrained situation mostly from the perspective of energy costs. Another objective in the context of ageing infrastructure is to use the system reliability indices or cost of unserved energy in the objective formulation to safeguard the network performance. Gradually, as the role of distributor is separated from the combined role of distributor and retailer, the role played by distributors becomes more of a distribution network owner to maximise asset utilisation as well as a network operator to deliver SG services.

2.2.1 Cost and loss minimisation

The operational costs of a combined entity of distributor and retailers include energy costs, asset maintenance and network electrical losses.

The total costs are optimised in this section without the use of variable pricing signals. A pool- and contract-based market model is proposed in [30] to encompass the wholesale generation companies, distribution companies with DG and load curtailment, and independent DG owners. [31] improves the model and focuses on the options of many distribution companies in multiple trading periods. DG integration to the pool-based wholesale energy and capacity markets is proposed in [32]. In [33], distribution companies assume the roles of distribution network operator and demand aggregator, which operate in the two-stage framework of day-ahead and real-time models. An active management scheme for energy management systems is proposed to combine the operations of renewable generation and responsive demand with SG infrastructure [34]. An hour ahead pool-based demand response exchange is proposed in [35] with separate predictions of demand curve and buyers' marginal benefit, which is improved in [36] using an agent-based and decentralised market clearing scheme. It is proposed in [37] that customers can bid reserve offers in the electricity market where energy and reserve are jointly optimised. Demand-side resources are integrated in the day-ahead reserve market and the energy recovery is considered after the reserve deployment [38].

To provide cost information in an optimisation formulation, the monetary terms can be formulated in the form of the customer utility [39], the energy cost functions [40], or the annualised energy cost saving [41]. Multiple DERs can be scheduled with an energy cost minimisation objective [42] [43] or with multiple objectives together, such as the minimisation of energy cost, peak load or CO_2 emission cost [44]. An incentive contract for demand management is designed depending on customers' willingness and load locations [45], and optimal contract pricing is designed for DG dispatch [46].

The non-linear electrical losses can be a significant portion of operational costs when losses are internalised in the utility. Traditional allocation methods are pro rata, quadratic and proportional allocation methods [47] considering DG [48] and network reconfiguration [49]. Marginal methods use load-flow Jacobian to track loss variations by expressing total losses in terms of nodal injections in Taylor series expansion [50]. Branch current methods are based on variations of real and reactive branch currents and their directions [51] [52] [53]. Summation methods can allocate loss on an ex-post basis, which are developed using power summation [54] and energy summation [55].

2.2.2 Variable price signalling

The list in Section 2.1.1 suggests many variable pricing structures are available to signal the desired electricity consumption, most of which signal energy costs only. Effectiveness of residential dynamic pricing varies depending on enabling technologies, design and geography [56]. The operational price formulations include spot pricing based on radial power line flows [57], nodal pricing or LMP for DG [58] [59] [60]. Price elasticity is the responsiveness of electricity demand to the changing electricity prices. An overview of tools enabling price elasticity of demand is provided in [61]. Cross-elasticity of demand is the responsiveness of electricity demand to the price of other goods, which has been used to derive time-of-use (TOU) pricing and identify load management potential [62]. Price elasticity of demand has been considered and incorporated in market clearing [63]. Modelling and simulation of demand-side bidding in the wholesale market are provided in [64] [65], [66], [67] and [68].

The home energy management system (HEMS) coupled with the smart meter has been developed as a DER scheduler, which responds to varying real-time price signals [69]. A detailed study of load mix is presented in [70] to identify feasible demand-side resources and to generate demand-side bids for the demand aggregator. Data mining in the demand database and load response modelling are applied to classify customers and find opportunities in day-ahead and real time markets [71]. An automated residential energy automation system is formulated in [72] to optimise appliance operation and building automation with price prediction and load control capabilities.

There are several issues with the above DER scheduling category. The first issue is the loss of load diversity [73] or the creation of a new demand peak [74] if all TCLs respond to the same price signal. The second issue is related to the difficulty of predicting wholesale market prices for optimal energy consumption scheduling [75] [76]. Finally, the HEMS usually has limited computation resource, so the issue is that some types of DERs require higher time resolution data, while others require longer scheduling horizon [77].

2.2.3 Delivery reliability centred distributor operation

To provide an acceptable level of delivery quality with cost-efficient investment, system reliability is now the common index to be optimised in network planning practice. Outage costs are minimised as a function of outage frequency, outage duration, network configuration, switch location, and lost load and its value [78]. Investment costs and unsupplied energy costs are minimised in [79]. Cost of expansion is minimised to generate a pool of solutions for several alternative topologies in the initial stage, and reliability indices and reliability costs are computed in later stages to enable reconfiguration while meeting reliability requirements in [80]. Distributed generation, cross connections, distribution lines, transformers and reliability costs are simultaneously optimised in [81].

Pricing based on network reliability has been explored as well. Real-time priority pricing for customers with various reliability requirements is proposed in [82]. Expected reward or penalties for service disruption payments can be estimated by reliability index probability distributions [83]. Distributed generation can be dispatched as in [84] by considering hourly reliability worth. The cost-benefit analysis of DSM is performed with reliability worth [85]. A reliability-based distributor pricing model is proposed to recover investment-related costs [86]. Pricing can be based on network security subject to N-1 contingencies [87] using sensitivity analysis [88]. The performance based rate making (PBR) also introduces reward or penalties to distribution network operators [89], which is another form of pricing signals.

2.2.4 Demand shaping and asset utilisation strategies

It is argued that DERs should be operated to satisfy the local distribution network constraints, such as the current and voltage limits, to achieve the objective of maximizing asset utilisation. ESS can provide for load levelling [90]. The mutual influence between the distribution network and DR can be seen in terms of the unbalanced phase currents and voltage variations [91]. Focusing on the medium voltage (MV) distribution network, the voltage sensitivity coefficients from the Jacobian matrix are used to satisfy the voltage constraints in the DER scheduling with high renewable penetration [92]. Focusing on the low-voltage (LV) distribution network, a three-layered control structure is proposed to maximise the LV network utilisation iteratively considering the voltage profiles [93]. The voltage profile, current constraint, capacitor and transformer tap settings are formulated in the MV network optimisation, to schedule the ESS with PV [94], to schedule the PEV charging in unbalanced three-phases [95], or to schedule the controllable loads [96]. Dispatching the PV inverter real and reactive power can also improve the three-phase balance in LV network [97].

2.3 Distributor regulations and business models

The evolving distribution regulatory policy and business environment are reviewed in this section, starting from the rate of return regulation to incentive regulation, then from the performance based regulation to the new regulatory thinking in SG, with potential hurdles to SG development. The investment cost allocation methodology is closely related to the distribution network pricing structure, and the avoided cost approach is relevant to the pricing of DERs.

2.3.1 Evolution of distributor regulatory framework

Examining the overseas distribution network regulations and policies, the rate of return regulation, also known as cost of service regulation, had facilitated the process of infrastructure investment and expansion in the past. However, concerns on the rate of return regulation were that business practices tend to be less efficient, avoid risk-taking or forgo investment in research and development [98]. Incentive regulation was then introduced, such as revenue-cap or price-cap regulation, so that the cost reduction and efficiency improvement can be a source of profit retained by distributors showing higher investment rate and profitability [99]. However, distributors tend to cut operating expenditure under cap-based regulation, leading to deteriorated service quality [100] and encouraging electricity sales volume while discouraging other more efficient resource decisions [101]. As a result, performance based regulation was later introduced by many regulatory agencies around the world to include the punitive or incentive clauses for performance with ageing infrastructure.

In the SG context, regulations may evolve to focus on innovation, efficiency, renewable, or a combination of the above. An example of innovation initiatives in regulatory thinking can be found in the RIIO (Revenue using Incentives to deliver Innovation and Outputs) regulatory framework [102] to be adopted by the UK Office of the Gas and Electricity Markets (OFGEM) in 2015. RIIO retains the regulatory philosophy of the existing price control regulations but added some modifications to reward forward looking innovation and flexibility in the long-term. The other example of policy is energy efficiency in the US [103]. The Energy Efficient Portfolio Standard (EEPS) aims to reduce the higher cost of constructing new peak generation resources and provide options for consumers to control energy costs [104]. The energy efficiency programs are aggressively funded by several states in the US [105]. Recently, renewable generation has attracted more attention due to the awareness of climate change, represented by the example of Feed-in-Tariff (FIT) to guarantee purchase price for renewables by government within a certain time period. The short regulatory history review shows that regulatory regimes are responsive to the evolution of the distribution sector.

However, some hurdles still exist to prevent the SG transition using a market mechanism. Firstly, the technological decisions are highly influenced by the political climate. In the UK, 'regulatory regimes are influenced by political change and ultimately controlled by the Parliament and Ministers' [106]. In the UK, the power boundary between the industry regulator and competition authority may have been drawn [107], but their objectives may not be consistently aligned [108]. Secondly, distributors generally are facing the situation that changed from over-investment in the past to under-investment now [109] with the increasing difficulty in obtaining capital at reasonable cost [110]. The current commercial environment and regulatory framework discourage taking financial risks to realise long-term benefit, which prevent the distributors from deploying some mature SG technologies [111]. Lastly, social reaction can be uncertain to regulatory change, which is illustrated by an example in [112] where a promising state-funded efficiency program has been turned into an unexpected media disaster due to the implanted device being inside residential premises. However, the industry and regulators should not be discouraged, but instead should move on to 'the next best practice' [113].

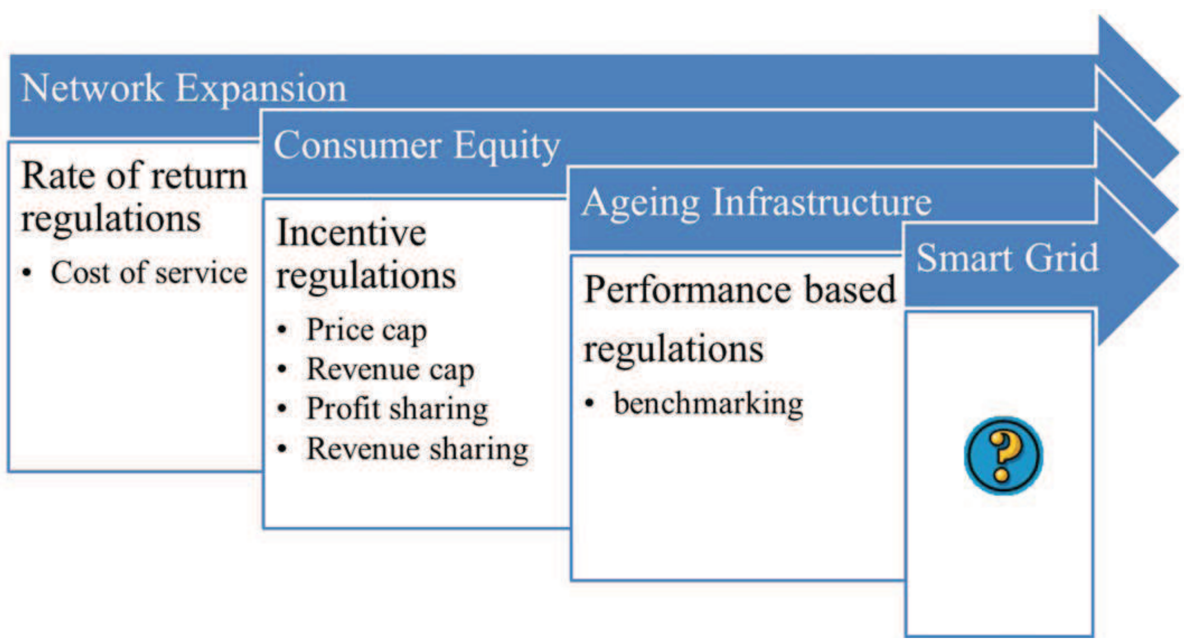

Figure 2.1: Evolution of regulatory regimes with evolving industrial and social objectives

Figure 2.1 [114] summarises the above trend of the regulatory objectives with the changing industry focus. It shows that more and more regulatory elements have been added during the past century to the existing framework. New Zealand distribution network regulations have also followed similar trends of evolution.

2.3.2 Investment cost allocation methodologies

A traditional cost-of-service study [115] suggests the charges can be energy, demand or customer related. Energy related charges are variable charges based on the electricity volume consumed. Demand related charges are fixed charges for investment and expenditures to provide capacity under maximum load requirements. Peak capacity is one of the key drivers of distribution network asset investment whose proper allocation is the core of distribution tariff setting or distributor pricing structure. The uniform allocation method [116] is applied to marginal energy, reliability and investment costs, considering price elasticity of demand and demand-side management. The power-to-current distribution factors are derived from load-flow studies, which reflect the 'extent-of-use' of distribution fixed assets [117]. The transition issue is discussed in [118] for distribution network companies around the world to move from a cost-averaging to a cost-causation structure with and without DG. The 'MW-MVAr-Miles' methodology is proposed in [119] to reflect the three key cost drivers of distribution network investment.

As many networks have been built decades ago and the present objective of network operators is to reinforce the network as demand growth, and the marginal or incremental based methods draw practitioners' attention. Long run marginal cost (LRMC) pricing is usually considered as forward looking and economically efficient [120], which can be allocated hourly to indicate peak load [121], or allocated on distance and reactive power support [119]. LRMC pricing based on network spare capacity is proposed in [122], and revenue reconciliation is discussed in [123] using the sensitivity based analytical method, and the other solution is to use the fuzzy set to model load uncertainties [124]. It is also realised that proposals of fixed asset investment projects are made in an incremental fashion to reinforce the existing network, so the long run incremental cost (LRIC) pricing approach is developed in [125] to reflect fixed asset utilisation in the distribution network. An economic efficiency framework is proposed for comparing different long term pricing models in [126].

2.3.3 Deferrable network investment costs

Deferred network investment is one of the major benefits offered by DG or ESS. The deferred investment value or avoided cost can potentially be used for pricing of other SG technologies and DSI approaches because long-term savings can be achieved for the overall industry. In distribution network planning, future network capacity requirements and configurations can have a planning horizon covered for more than 20 years [127]. The evaluation of deferred investment for DG is usually done on a yearly basis [128] with different DG ownership rules and regulatory incentive structures [129]. The value can be derived from a normal planning process [130] or calculated by successively eliminating the least cost-effective expansion option from an over-built network [131]. Pricing can factor in the negative demand growth [132] and non-utility generation [133]. For non-utility generation, the pricing assessment firstly treats utility or non-utility generation as the same to derive overall the network benefit, but later attributes the part of benefit to non-utility generation providers. The DG pricing model in [134] is also based on deferred investment, but includes more considerations of DG benefit, such as the avoided electricity purchase, loss reduction, reduced market price volatility and reserve capacity provision.

Chapter 3

Simulation of a De-regulated Market

Section 3.1 in this chapter outlines the electricity market structure in the de-regulated environment with brief discussions of the various market stakeholders and their roles related to the demand side of the electricity market. Distribution network companies are central to the role of demand-side resource integration, so the focus is on their traditional role as the distribution network asset owner as well as their evolving role as the distribution system operator (DSO). Section 3.2 discusses the simulation and modelling methodologies to investigate the emerging initiatives in DSI under SG environment. Different software platforms have been developed for various study purposes. The standardised test networks have been used to demonstrate the implementations, whose general features are explained to justify the different choices of test networks used in the following chapters. Some practical data were available publicly, while others have been obtained through industry projects.

The two following sections in this chapter address two technical issues related to DSI. Section 3.3 presents the background of nodal electricity market formulation. The automated simulation demonstrates the derivation of nodal prices either from a test transmission network or the historical trading data, by changing the demand profiles or other network constraints. While Section 3.3 covers the electricity market on the high-voltage transmission grid side, Section 3.4 discusses the modelling issues on the other end of the network, which presents the modelling and simulation framework for the low-voltage (LV) distribution network close to the customer side. Chapters 4, 5 and 6 will be more focused on the various aspects of DSI in the distribution networks, so these two sections in this chapter complete the implementation loop for the following three chapters.

3.1 Stakeholders in the electricity market

In a de-regulated electricity market structure, such as the one in NZ, the electricity industry has been restructured into several sectors, including the generation companies, the independent transmission system operator and market scheduler, the distribution network companies and the electricity retailers. There are also entities providing services to the electricity market operation, as well as the government agencies who regulate the activities of various entities.

3.1.1 Generators and retailers

Generation companies own the large centralised power plants that produce electrical power from various energy sources. In electricity spot market trading, generation companies offer to sell power either as energy or reserve. In the New Zealand Electricity Market, the reserves are categorised as the fast instantaneous reserve (FIR) or sustained instantaneous reserve (SIR) [135], which are the standby generators or interruptible loads to back up the sudden loss of a generator and to keep the system frequency from dropping further. Certain generators also participate in the ancillary service markets, such as frequency keeping, reactive support and black-start, but these ancillary services are auctioned separately from the spot market. Demand-side resources can also participate in the ancillary service market, such as frequency keeping and frequency regulation markets.

With the recent implementation of demand-side bidding scheme, retail companies and some large electricity users are able to bid in the wholesale spot market and buy power in aggregate. Retailers engage with individual customers of various consumption sizes and types and design retail packages to attract customers. In New Zealand, the process for electricity customers to choose among different retailers has been made easy, but small residential and commercial customers in general still pay for electricity at the fixed retail rate. There are some subsidiary retail companies offering retail packages based on the variable wholesale market price, but most of the retail packages still shield the customers from the volatility of the wholesale market price variations.

One unique structure in the NZEM is that some major generation companies are usually associated with the major brands of the retail companies. Therefore, if a major retail company made a loss in the wholesale market due to price hike, it is likely that a profit may be gained by its associated generation company. This arrangement creates some natural hedge mechanism to avoid the substantial loss in wholesale market trading.

3.1.2 Independent system operator and market scheduler

In the de-regulated market structure, the functions of the independent system operator and market scheduler are to collect market bids and offers, and at the same time run system simulations against grid operating constraints. The market scheduler publishes generator dispatch schedules with the corresponding nodal prices, and the system operator sends out generator dispatch instructions according to the final schedule at the market trading gate closure for a trading interval. The system operator and market scheduler in NZ is the state-owned enterprise - New Zealand Transpower Limited, who plays a very important role to ensure the efficient and fair market operation.

3.1.3 Market services and aggregators

To facilitate the electronic transactions of bidding and offering, the trading platform is developed similar to a stock trading scenario, such as the wholesale information trading system (WITS) in the New Zealand Electricity Market. Market services also settle the market transactions and validate transactions against the actual power metering.

The aggregator is technically specialised in certain demand-side initiatives, such as demand response (DR) or electric vehicle (EV) charging, to ensure the demand-side services also meet the wholesale market requirements. Retailers or distributors sometimes also take the role of aggregator to develop demand-side resources, because they both have access to the customer base and understand the market operation. A widely known example of service aggregation developed by New Zealand distributors is the control of hot-water cylinders to manage their network peak, but increasingly these services are acquired by retailers to help with DR bidding.

3.1.4 Distributors as network asset owners and operators

Traditionally distribution networks were passive networks, because there was not that many active distributed generation (DG) being integrated to the networks. As a result, the role of distributor was more of an asset owner whose job was to invest and maintain the distribution assets. The means of generating revenues for distributors have been gradually changing during the evolution of the distribution network regulations as outlined in Section 2.3. Due to these changes, the business models of distributors were also changing to comply with the rules.

As SG development continues, more distributed energy resources (DERs) start to be integrated into the distribution networks. As more and more customers start to own generation equipment and the associated distribution equipment, the ownership of assets related to the distribution network diversifies. The retailers or aggregators may invest in their own control and signalling equipment for automated demand response (ADR). Customers may invest in their own rooftop photovoltaic (PV) generation with electricity storage systems (ESS). Intelligent household appliances connected by communication networks that can be controlled for grid frequency or peak management may be subsidised by the transmission grid system asset owner.

Therefore, it is expected that the role of a progressive distributor will gradually shift towards the role as a distribution network operator. The distributor as the asset owner manages the traditional network based assets, such as distribution lines and distribution transformers, while the distributor as the network operator schedules various DERs to ensure efficient utilisation of all assets owned by different stakeholders.

A crucial factor to this transition is the way that distributors derive their revenues from their distribution network asset base, which is also governed by the distribution regulations. Although the distribution regulatory framework, such as the revenue equals incentives plus innovation and outputs (RIIO) framework in the UK, starts to recognise the role of SG innovation in long-term network development, it is expected that the traditional regulatory elements will still be effective along with SG development. Therefore, the entire thesis is based on the belief that the SG development takes place under the influence of traditional economic regulation, but the regulatory framework will eventually adapt to the SG needs and gradually incorporate more innovative elements. This thesis serves to facilitate the transition of the distributor through this journey.

3.1.5 Grid, network and market regulators

As regulated businesses, the total revenues of most of the electricity distributors in New Zealand are overseen by the Commerce Commission of New Zealand (competition regulator) through the 'CPI-X' regime over a five-year regulatory period, which are also related to the overall network delivery quality or the so called price-quality (PQ) path. The Commerce Commission also approves the investment proposals of transmission grid upgrades, so the portion of the electricity bill related to the transmission grid tariff is also regulated.

While the 'CPI-X-PQ' regulates the distributor revenue holistically, detailed pricing principles for allocating the total costs to different electricity customer groups are set by the Electricity Authority of New Zealand (industrial regulator) to 'promote subsidy-free, efficient, responsive and transparent pricing structures that are transactionally equivalent to all retailers. The Electricity Authority works with the market scheduler to improve the market design, such as by implementing demand-side bidding and demand dispatch. The Electricity Authority also oversees the operations of various market participants.

3.1.6 Electricity customers

Electricity customers are typically classified as residential, commercial, industrial and sometimes rural/agricultural. The size of consumption in each classification varies, and can be measured either as the total monthly energy consumption or the maximum peak power consumption. Small customers usually do not participate in electricity market trading directly but through their retailers or aggregators to minimise the transaction costs.

Traditionally customers are used to the perception that electricity usage is the basic need of modern citizens, so forced outage or blackout often makes the headlines. The development of SG coupled with pricing information essentially introduces the market mechanism to influence customer behaviours. The customer behaviours and wants are the most variable factors, which are outside the scope of this thesis. However, electricity pricing itself alone may not be sufficient to influence customer behaviour. Service differentiation, technology innovation, fashionable lifestyle and new forms of media communication must all be considered to complement electricity pricing to achieve the desired outcomes.

Therefore, it is reasonable to assume that enterprises are rationally pursuing profit maximisation in many cases, but the same assumption does not apply to the individual electricity customer who may often make irrational decisions rather than maximise profit. The optimisation formulations in Chapter 5 and Chapter 6 also reflect the above view-point, which attempts to factor in the service differentiation and guard customer satisfaction respectively.

3.2 Simulation and modelling methodologies

The integration of demand-side resources is demonstrated using software simulation and network modelling. Different software have been selected to enable the best software features and functionalities for the specific purposes, which also allows customised network analysis, device modelling and optimisation formulation. Standardised power system test networks are used to demonstrate the implementation, which allows the results to be recreated or continued in future work. Some practical network data have been obtained through industry projects, however, due to confidentiality, only the standardised test network results are presented in the thesis.

3.2.1 Software integration

Figure 3.1 shows the interconnection among simulation software.

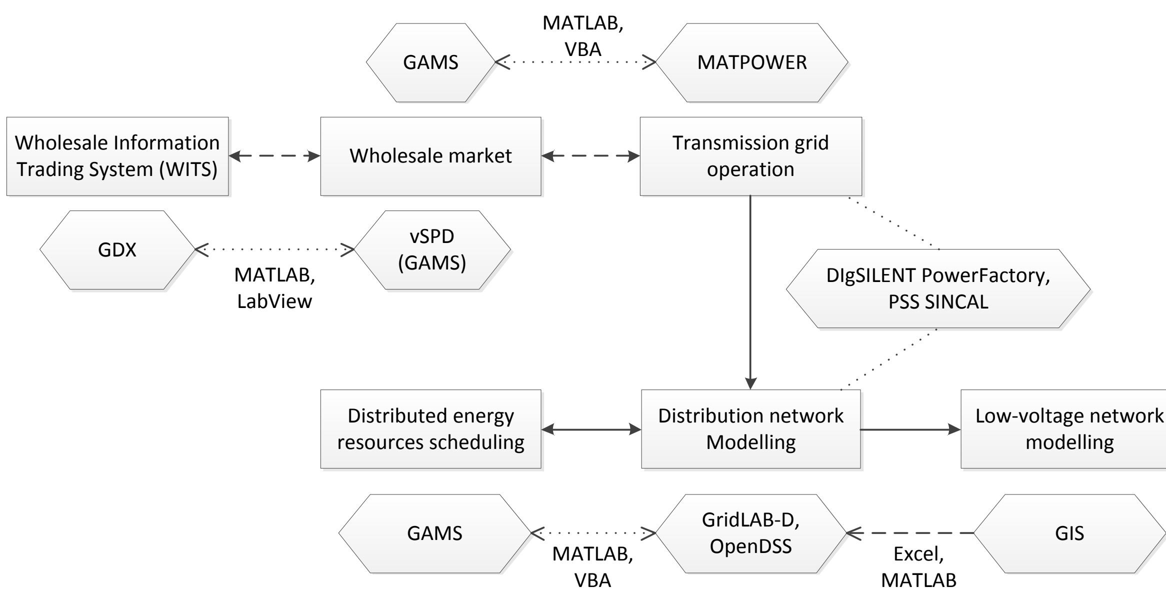

Figure 3.1: Integration and interconnection among simulation software

The General Algebraic Modelling System (GAMS) software is specialised in optimisation formulations and solvers, which is also used by the Electricity Authority to create the vSPD software platform that emulates the New Zealand Electricity Market formulation and trading. GAMS is also used to formulate a network optimisation algorithm, showing the optimal coordination of demand-side resources. GAMS can be automated by MATLAB or Excel VBA, through the use of

GDX reading and writing functionalities. The LabView software has been developed in previous projects to fetch real-time nodal prices from the WITS website through the Internet.

GridLAB-D and OpenDSS are both open source distribution network analysis software, which have been used extensively for network simulation and distribution resource modelling. GridLAB-D is specialised in physical load modelling in time series for various types of residential appliances, and is capable of solving three-phase unbalanced load-flow with distributed resources. OpenDSS is capable of short circuit analysis and harmonic analysis in addition to load-flow analysis, using the component object model (COM) automated by either MATLAB or Excel VBA. DIgSILENT PowerFactory and PSS SINCAL are both commercial grade power system analysis software used by New Zealand companies. PowerFactory uses DIgSILENT programming language to develop automated scripts, while PSS SINCAL uses the COM interface similar to OpenDSS.

3.2.2 Choice of standardised test networks

The IEEE 123-node distribution test network has been used in Chapter 4 to demonstrate the distribution network planning and investment cost reconciliation, which was the largest distribution test network before the IEEE 8500-node distribution test network. The problems of voltage drop and near loading peak are often triggers of distribution network reinforcement.

The distribution network extended from the IEEE RBTS Bus No. 2 has reliability indices and component failure rate statistics, which fits the purpose of simulating the network service quality in Chapter 5.

The IEEE 8500-node and 4-node distribution test networks have been implemented in Chapter 6. The largest 8500-node distribution test network is suited to show computation performance, while the simulation results from the smallest 4-node distribution test network are given in details to facilitate discussions and help interpretation.

3.2.3 Practical data availability

The historical wholesale market trading data is available on-line publicly, so that ex-post analysis of the electricity market activities can be performed to trace back the effect of aggregated demand-side resources on the electricity market.

The transmission grid data and some medium-voltage distribution network data are available in the centralised dataset, which have been requested from the Electricity Authority in confidence. The networks are modelled with the commercial grade power system analysis software - DIgSILENT PowerFactory.

The low-voltage distribution network data of Vector Limited - the largest distribution company in the Auckland region - has been obtained through an industry project. The network component and connectivity data are extracted from the geographic information system (GIS), with the installation control point (ICP) connectivity information being matched by the monthly energy consumption data.

The major implementations demonstrated in Chapter 4, 5 and 6 of the thesis focus on MV distribution network planning and operation. The practical work shown in the following Section 3.3 and 3.4 completes the implementation loop, which demonstrates how the wholesale market dispatch part and the modelling part of the 'last-mile-to-customer' LV distribution network can fit into the thesis's theme.

3.3 Nodal formulation of the electricity market

The nodal electricity market structure has been established and operating in many Western countries or regions to improve market signaling and to increase generation investment activities. Wholesale market formulation and trading data are publicly available in New Zealand, so this section demonstrates the impact of demand side on the wholesale market prices. This section also shows how the benefit of integrating various distributed energy resources (DERs) can be derived from wholesale market trading.

3.3.1 Security-constrained economic dispatch

Since 1996, the system operator and asset owner of New Zealand's national transmission grid, Transpower Limited, implemented a bid-clearing system using security-constrained economic dispatch (SCED) for the New Zealand wholesale Electricity Market (NZEM). The SCED is based on the DC optimal power-flow formulation, which produces the full locational marginal prices (LMP) at all grid nodes. The SCED functionalities are realised by the scheduling, pricing and dispatch (SPD) software.

In the current SPD formulation for SCED [135], the equality constraint is the nodal generation and load balance equation, where the right-hand side of the equation is bus net injection:

$$PG_m - PD_m - Plss_m = Sb \sum_{m=1}^{M} B_{mm'} \cdot \theta_{m'} \tag{3.1}$$

where

- m,m' is bus index,
- M is total bus number,
- $Plss_m$ is equivalent network loss at a bus,
- PG_m is per unit generation,
- PD_m is load,
- Sb is base MVA,
- $B_{mm'}$ is the mm'^{th} element of network admittance (susceptance) matrix, and
- θ'_m is bus angle in radian.

The capacity constrained branch flow is approximated as:

$$BFlow_j = Sb \cdot B_j \cdot \Delta\theta_j \tag{3.2}$$

where

- $BFlow_j$ is per unit real power-flow of a branch,
- B_j is per unit admittance (susceptance), and
- $\Delta\theta_j$ is bus angle difference in radian.

The branch losses are modelled as a piece-wise linear function of branch flow segments with the corresponding loss factors:

$$Bloss_j = \sum_{bs=1}^{Nbs} BFlow_j\,(bs) \cdot LF_j\,(bs) \tag{3.3}$$

where

- $Bloss_j$ is piece-wise linear branch losses,
- bs is loss segment,
- Nbs is total segments, and
- $LF_j(bs)$ is loss factor.

Transpower has implemented the simultaneous feasibility test (SFT) to calculate thermal constraints in real time, which uses AC decoupled load-flow and feeds thermal constraints to the SPD.

3.3.2 Simulation on a test transmission grid

To demonstrate the simulation of a nodal electricity market formulation, the lossless dispatch according to [136] is implemented in the General Algebraic Modelling System (GAMS) [137] software. MATPOWER [138] is a MATLAB based software, which has been used to run an AC load-flow to obtain the AC branch losses. The MATLAB software can call GAMS and exchange parameters, variables and equation values with GAMS. After feeding the real-time branch losses into the GAMS dispatch calculation, the lossless dispatch then becomes dispatch with branch losses [139] as shown in the following case study. Similarly, branch flow constraints, angle constraints, voltage constraints, generator output constraints and other constraints can be calculated in MATPOWER and imported into GAMS.

The IEEE 30-bus network case study set-up

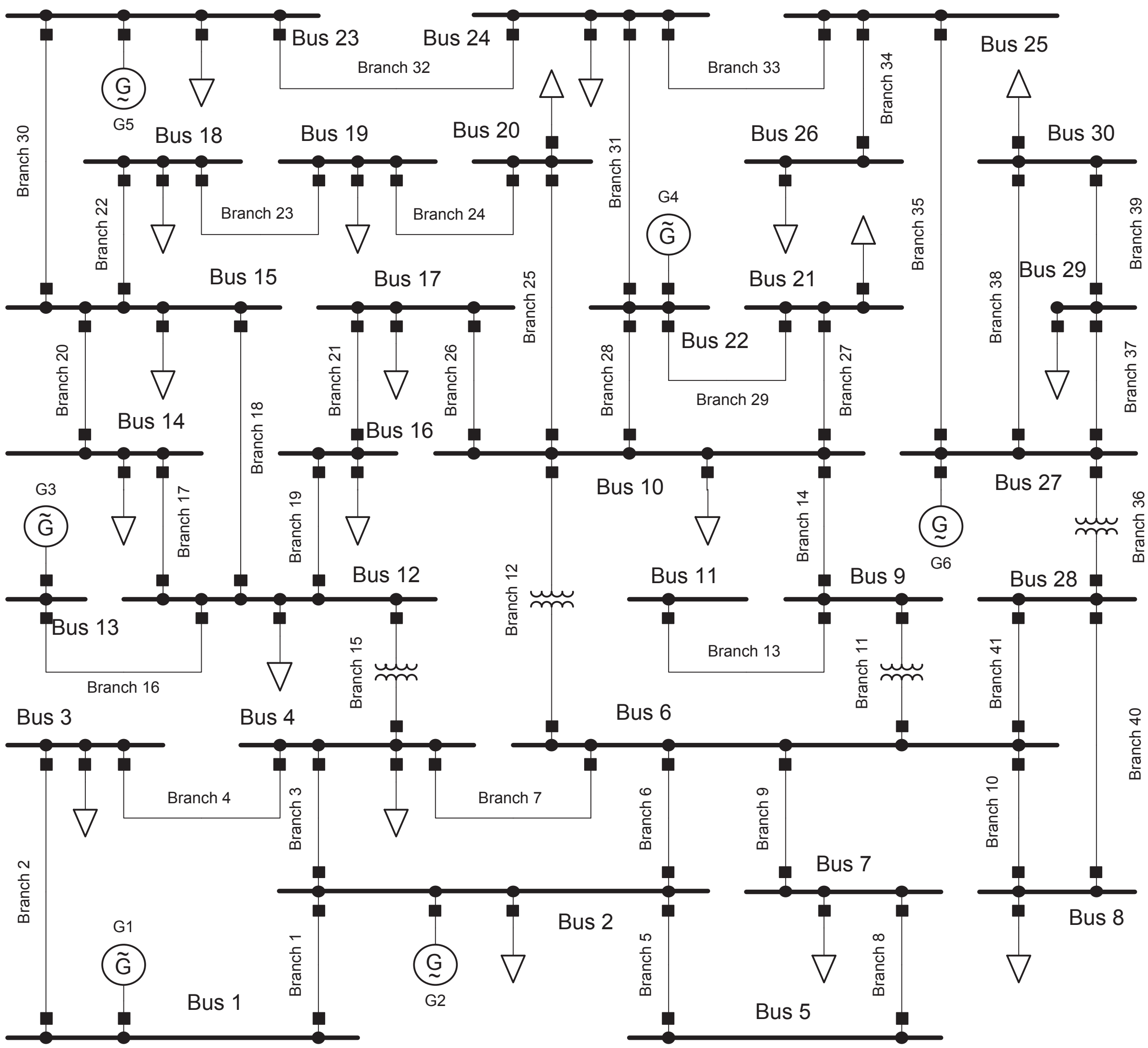

Figure 3.2: The IEEE 30-bus network.

The IEEE 30-bus network, as shown in Fig. 3.2, has been implemented as a case study for nodal market price simulation.

The primal problem is restated as the following:

$$\min PC = \sum_{k=1}^{TB} GC_k \cdot PG_k \tag{3.4}$$

The above objective function is subject to:

$$\sum_{m' \in \Theta_{mm'}} \left(B_{mm'} \left(\theta_m - \theta'_m\right) + B_{m'm} \left(\theta'_m - \theta_m\right) - \frac{Ploss'}{2} \right) + \sum_{k \in m} PG_k = PD_m \quad \forall m \in M \tag{3.5}$$

$$0 \leq PG_k \leq PGm_k \tag{3.6}$$

$$-Bcm_{mm'} \leq B_{mm'} \left(\theta_m - \theta_{m'}\right) \leq Bcm_{mm'} \qquad \forall m, m' \in \Theta_{mm'} \tag{3.7}$$

$$\theta_1 = 0 \tag{3.8}$$

where

- PC is total cost in dispatch,
- k is trade block,
- PG is dispatch of generators,
- TB is total trade blocks,
- PGm_k is maximum generation specified in a trade block,
- $Ploss'$ is the calculated AC branch losses,
- GC_k is generation price specified, and
- Bcm is maximum capacity of a branch.

The branch flow capacity is listed in Table 3.1 and the generator cost data in Table 3.2.

Table 3.1: Branch Flow Limits (MW)

j	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Bcm	130	130	65	130	130	65	90	70	130	32	65	32	65	65
j	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Bcm	65	65	32	32	32	16	16	16	16	32	32	32	32	32
j	29	30	31	32	33	34	35	36	37	38	39	40	41	-
Bcm	32	26	16	16	16	16	17	65	16	16	16	32	32	-

Table 3.2: Generator Trade Blocks and Offers

Generator No.	G1	G1	G2	G2	G3	G3	G4	G4	G5	G5	G6	G6
Trade Block k	1	2	3	4	5	6	7	8	9	10	11	12
PGm_k (MW)	40	40	40	40	20	20	25	25	15	15	27.5	27.5
GC_k (\$/MWh)	3.6	5.2	3.2	4.6	4	5	4.1	7.25	3.75	4.75	3.7	4.2

Variation of simulation conditions

To investigate the variation of nodal prices and generator dispatch, the base case scenario is modified by three factors: either using the original demand or increasing all demand by 2%; either keeping the branch flow maximum capacity constraint on or off; either running the lossless dispatch or the dispatch with losses. Therefore, there are eight combinations of results, which are selectively listed as generators dispatch in Table 3.3 and LMP variations in Table 3.4.

Table 3.3: Dispatched generators in the IEEE 30-bus network (MW)

PD **% loading factor**	100%	100%	102%	102%	102%
Branch flow limit included	Y or N	Y or N	Y or N	N	Y
Branch losses included	N	Y	N	Y	Y
G1 TB1	40	40	40	40	40
G2 TB3	40	40	40	40	40
G2 TB4	0	0	0	0.77	0.14
G3 TB5	20	20	20	20	20
G4 TB7	25	25	25	25	25
G5 TB9	15	15	15	15	15
G5 TB10	0	0	0	0	0.64
G6 TB11	27.5	27.5	27.5	27.5	27.5
G6 TB12	21.7	24.31	25.48	27.5	27.5

Discussions of generation dispatch and nodal prices

The effect of branch loss, demand change and branch flow capacity can be seen by comparing the columns of Table 3.3 and Table 3.4 in reference to Table 3.2.

Losses can be considered as additional load in the nodal balance equation, so incorporating the transmission losses only affects the dispatch of the marginal generator. In the first two columns of Table 3.3, the marginal generator is G6 with trade block 12. The effect of loss is the most noticeable if including the branch loss results in choosing a different marginal generator, which can increase all nodal prices from $4.20/MWh to 4.60/MWh.

Table 3.4: Nodal marginal prices in the economic dispatch of IEEE 30-bus network ($/MWh)

PD **% loading factor**	100%	100%	102%	102%	102%
Branch flow limit included	Y or N	Y or N	Y or N	N	Y
Branch losses included	N	Y	N	Y	Y
Node 1	4.20	4.20	4.20	4.60	4.601
Node 2	4.20	4.20	4.20	4.60	4.600
Node 3	4.20	4.20	4.20	4.60	4.604
Node 4	4.20	4.20	4.20	4.60	4.604
Node 5	4.20	4.20	4.20	4.60	4.598
Node 6	4.20	4.20	4.20	4.60	4.595
...	...	...	...	...	...
Node 13	4.20	4.20	4.20	4.60	4.665
...	...	...	...	...	...
Node 22	4.20	4.20	4.20	4.60	4.714
Node 23	4.20	4.20	4.20	4.60	4.750
Node 30	4.20	4.20	4.20	4.60	4.297

Similarly, comparing the second columns with the fifth columns of Table 3.3 and Table 3.4, increasing 2% of demand has resulted in choosing the more expensive marginal generator of G2 with trade block 4. Therefore, most of the nodal prices have increased from $4.20/MWh to the 4.60/MWh range. In other words, if demand can be reduced by 2%, the overall payment to purchase power can be reduced by approximately 10% in this case.

The aggregated benefit of demand-side participation can be quantified using a similar methodology depending on the generator offers and transmission grid conditions.

3.3.3 Ex-post analysis of scheduling, pricing and dispatch results

The actual benefit of demand-side integration can be quantified if necessary, using the practical data of the historical generation offers, load bids and constraints stored in the wholesale information trading system (WITS). The data have been processed in GAMS data exchange (GDX) format for input to the vectorised SPD software (vSPD) maintained by the Electricity Authority [140].

Generation companies and retailers in New Zealand have been using the vSPD software to conduct the trading analysis on a half-hourly basis with real-time data feeds.

All of the ex-post daily GDX input files can also be downloaded from the Electricity Authority website for analysis. The vSPD can be repeatedly run by MATLAB or Excel VBA for every trading period over a certain time period. Therefore the total benefit of demand-side participation can be accumulated. To change the demand profile, the GDX input files need to be updated. MATLAB initially calls GAMS to read all sets and parameters that are related to the demand from the GDX input file. The 'uels' and 'val' properties control the data storage format and the actual data values in the GDX files. After returning the parameters back to MATLAB with the correct GDX format, MATLAB can then modify the values of 'val' to update the demand profile. Lastly MATLAB calls GAMS to write all sets and parameters back to the GDX input file for GAMS execution.

3.4 Modelling of large-scale distribution networks

Stepping down from the high-voltage (HV) transmission grid to the medium-voltage (MV) primary distribution networks, electrical power is then delivered through the low-voltage (LV) secondary networks to households. Traditionally, these last miles are not modelled in the network studies, so the loads are aggregated at the MV/LV distribution transformers and used in MV network studies. However, as more DERs penetrate at the household level, their network effect must be understood and optimised before full deployment. Modelling the practical LV networks for a large city's distribution system poses the unique challenges that are addressed in this section.

3.4.1 Challenges of distribution network modelling

North American distribution grid is mostly served by MV with each distribution transformer serving a smaller amount of households than the counterpart outside North America. The LV secondary distribution networks outside North America are usually bulky, which can span over a large geographic area. LV networks in many different countries have diverse population densities and different network features. Due to the sheer number of components in LV networks, it is challenging to simulate the entire LV networks, assess each technology option on various feeder types with different loading conditions and then localise the problem with the best solution option for the investment policy overview. The major concern of LV networks is that the voltage profiles with distributed generation must be within the limits. With increasing PV penetration level, voltage fluctuation will further complicate the issue. The unbalanced phase condition and peak capacity of each single-phase are also important considerations in LV network modelling and simulation. It gets more complicated if using detailed voltage and current characterisation at individual home level with installation control point (ICP) in its full form.

3.4.2 Modelling framework for low-voltage network

Generic LV network modelling methodology

The flowchart, as shown in Fig. 3.3, is the generic modelling methodology proposed to process the LV network data and convert them to executable models for simulation. Excel spreadsheet is used

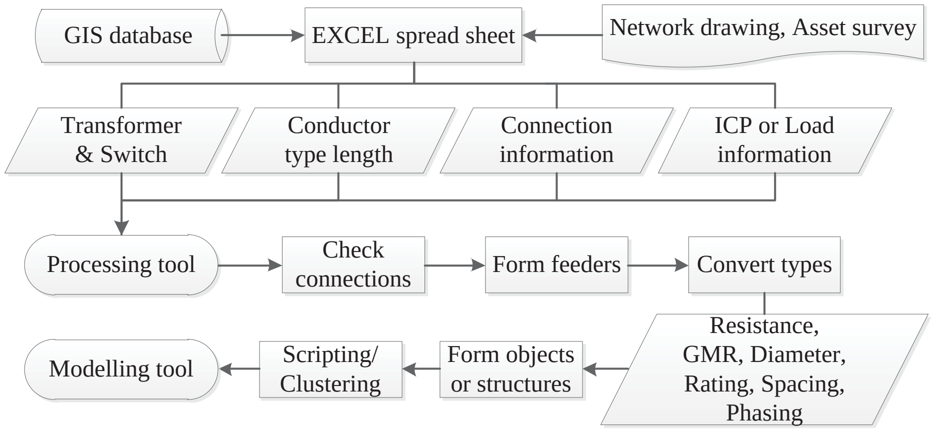

Figure 3.3: Flowchart for modelling LV networks

as a medium to transform the network data from the geographic information system (*GIS*) database or from the LV network drawings combined with the asset survey of physical components.Two types of software tools are used. The processing tool is to read the raw data, perform the pre-simulation calculation, and then script in the format suitable for simulation. The modelling tool is to perform the specialised analysis, such as load-flow or fault analysis. Many processing tools and simulation tools are available: *MATLAB* is chosen as the processing tool and *GridLAB-D* is chosen as the open source modelling and simulation software.

Network processing from GIS database

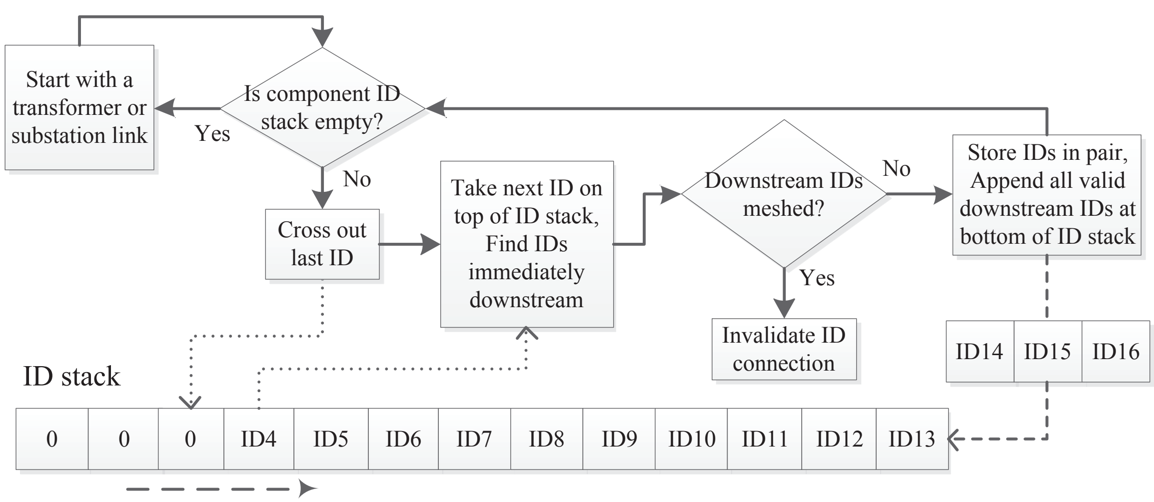

Figure 3.4: Mapping the radial feeder

All of the LV network feeders are mapped according to the algorithm, as shown in Fig. 3.4, using the valid component and connection data. Starting either from an *MV/LV transformer* or a *substation link*, the immediately downstream component IDs are identified and checked for radial characteristic before storing the connection in a pair of two IDs. This process is repeated into all laterals or branches, searching through all conductors, isolators or switches until no further connection can be found. All valid connections are mapped and stored using the structure format for further processing.

A flowchart, as shown in Fig. 3.5, is for processing all LV feeders to get the component types and the other modelling parameters. Starting from the top left, all conductors are firstly pre-checked for a type called *switching overhead line*, which are dummy modelling components migrated from the previous *GIS* database *Smallworld*. About 40% of these conductors are removed, so the connection information is also updated with the immediately downstream component ID.

Secondly, conductor types are processed and the unknown conductor types are estimated before converting to electrical and physical parameters. Next, installation control point (ICP) connection data are available from the distribution company but metering data related to ICP are maintained separately by the metering company. Since ICP data are commercially sensitive to release, an algorithm has been written to populate a given feeder with assumed ICP loads or solar panels according to the feeder capacity.

Following that, a typical LV cross-arm configuration for the overhead line system will be provided as well as percentage impedance data of typical MV/LV distribution transformers with different power ratings. Unknown transformer ratings are estimated according to current rating of the closest conductor. Lastly, the exact phase assignment data are not maintained by the distribution company, so another algorithm has been written to assign phases according to the available upstream conductor phase and loads.

Conductor parameters classification

Conductors, especially the underground cables, are important components that should be modelled in detail. All conductor types are coded into six specifications, as shown in Table 3.5. Based on the six specifications, other parameters, such as current rating, geometric mean radius and unit length resistance, are obtained from the supplier's data sheet in reference to the Australian and New

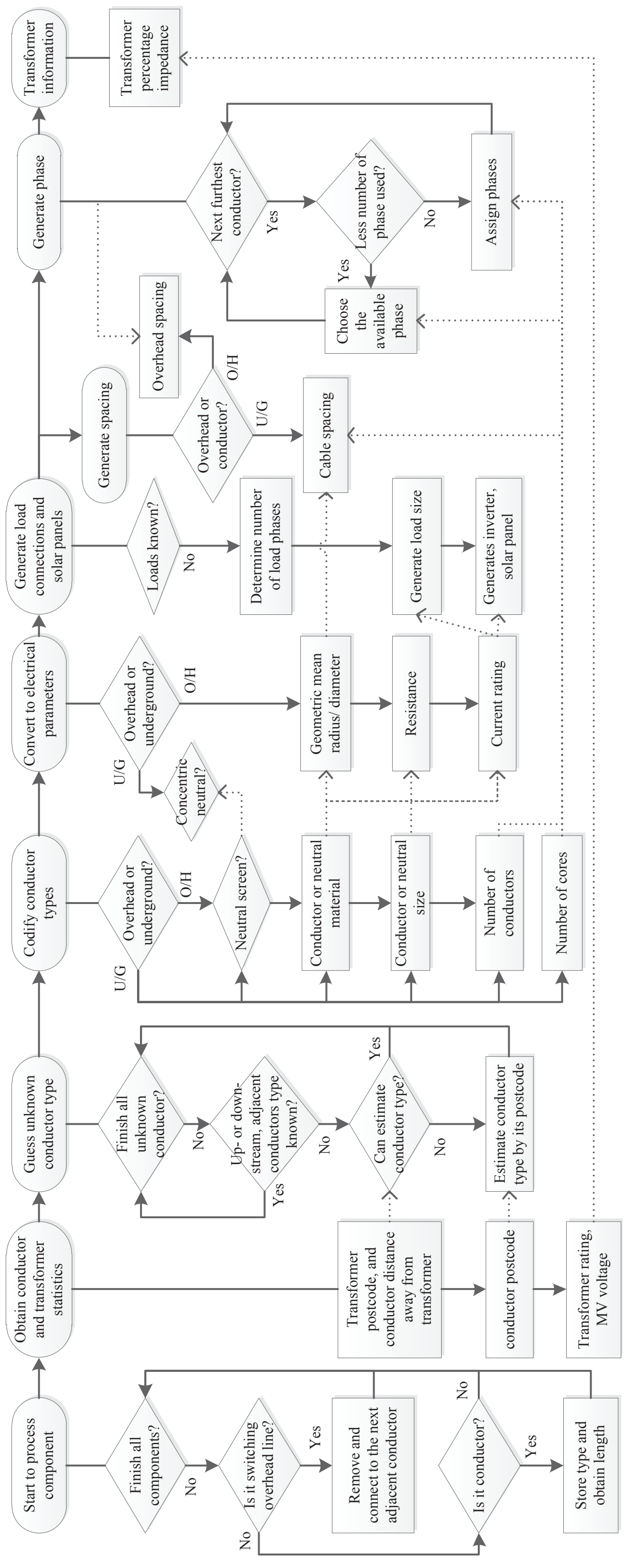

Figure 3.5: Flowchart for processing feeders

Zealand Standards, namely NZS5000, NZS4961, NZS3008.1.2 and NZS1125. The above parameter values are then fitted to the exponential function with respect to the conductor size, which produce very good extrapolations of other parameters once conductor size is known.

Table 3.5: Categorisation of conductor types

No.	Meaning	Example
1	Line or cable	1: overhead; 2: underground
2	Number of phases	1: single-phase; 3: three-phases
3	Number of cores	1: single; 2: double; and so on...
4	Material	1-5: Cu,Al,AAC,ACSR,AAAC etc.
5	Size (mm^2)	09500: 95 mm^2
6	Feature	1: neutral screen; 2: PVC; etc.

Further component attributes from *GIS* database files are transformer power rating and MV voltage, isolator/switch state, type and function, and conductor length and location.

3.4.3 Simulation of a practical low-voltage network

Software choice

GridLAB-D and *OpenDSS* are two open source simulation software implemented, which will serve different simulation purposes. *GridLAB-D* input file is in *txt* format with *.glm* extension, so the feeder information is scripted according to *GridLAB-D* software syntax using processing tool such as *MATLAB* or *Excel VBA*. The processing tool can also call *dos* command to run *GridLAB-D* on each individual feeder and read the load-flow results for further analysis. *OpenDSS* input file is also in *txt* format with *.dss* extension. The *COM* interface of *OpenDSS* can also link the other processing tools to automate the simulation process.

Distribution network modelling follows the steps as described in [141]. The software then performs the unbalanced three-phase distribution load-flow.

Using a computer with a quad 3.33 GHz Intel i5 processor and 4GB RAM, it takes less than 5 seconds to run one round of the iterative load-flow in *GridLAB-D* using the forward-and-backward sweep method on a medium-length feeder with nearly 2000 components, and 35 seconds on the longest feeder with 7600 components. Usually 2 to 5 rounds of iterations are required for each 10% interval of loads, so around 10-30 iterations for each feeder, for a total number of nearly 2000 feeders in various types. A linear relationship has been observed between the simulation performance and the number of components in the feeder.

In terms of the software performance, *OpenDSS* is much faster than *GridLAB-D*, but each has its own specialty, so depending on the study requirements, *GridLAB-D* is better if the interaction with detailed load models is required; but protection or harmonic analysis is only capable in *OpenDSS*.

Peak load data

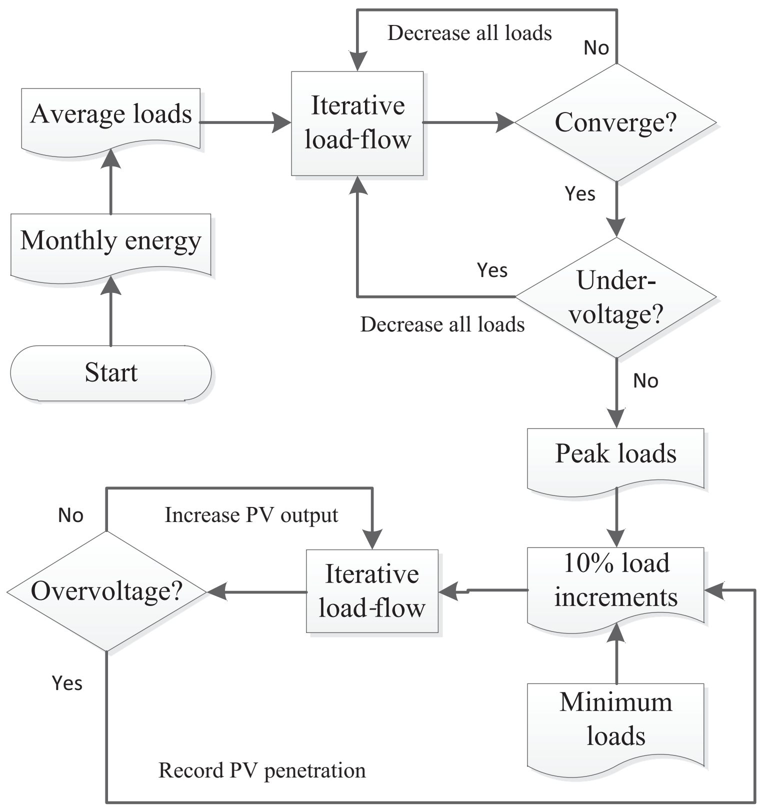

Figure 3.6: Iterative load-flow to calculate maximum PV output

Given the monthly energy consumption data at ICP, it is assumed 30 days in a month, and 8 hours of actively using electricity per day, so the monthly data is divided by a factor of 960 to get the 15-min demand data as the average real power of loads. A typical value of 0.85 power-factor is assumed for all loads, so the average apparent power of loads can be obtained. However, due to load diversity, not all loads would be operating at their average values at the same time. Therefore, the maximum coincident demand is much lower than the average power calculated using monthly energy data. To adjust this effect, the peak demand of a feeder is calculated iteratively for each individual feeder, as shown in Fig. 3.6, by lowering the average load at all ICP locations until the voltages at all ICP locations are above the minimum voltage limit. Essentially, a diversity factor is applied to each feeder to make the loading conditions more realistic.

PV penetration case study

$$PV_{pen} = \frac{PV_{ave}}{\Gamma_{ave}} \tag{3.9}$$

is a common definition of PV penetration level, where

- PV_{pen} is the PV penetration level,
- PV_{ave} is the average PV output power, and
- Γ_{ave} is the 15-min average load apparent power.

To investigate the voltage rise problem when PV output exceeds the local loads, the load profiles are divided into intervals of 10% loading each, starting from the minimum loads to the peak loads. It also assumes PV injections are at the same location as ICP loads, and the magnitude of PV output is proportional to the average ICP loads with unity power-factor. The same percentage increase is applied to PV output at all ICP locations, until any single-phase voltage across the feeder exceeds the maximum limit. This PV penetration level is recorded and the loading is increased by 10% for another set of load-flows iteratively.

Fig. 3.7 shows a partial snapshot of the PV penetration level at varying percentages of the peak loading. It can be seen that the feeders have different capabilities of supporting PV penetration. The PV penetration level gradually increases as the feeder loads increase, so the worst case scenario is when the feeder loading is at the minimum, and the PV penetration level is limited if there is no other PV supporting devices to mitigate the over-voltage. Therefore, the vertical line intercepts in Fig. 3.7 are the PV penetration levels of different feeders without any PV supporting device. Clearly for some feeders, the PV penetration level can reach very high without any supporting technology.

If the PV supporting devices are used, such as using the storage system to increase the effective loading of a feeder when the other loads are at the minimum, the PV penetration level can rise as most of the lines are upward sloping. The lines of the feeder PV penetration level also have different

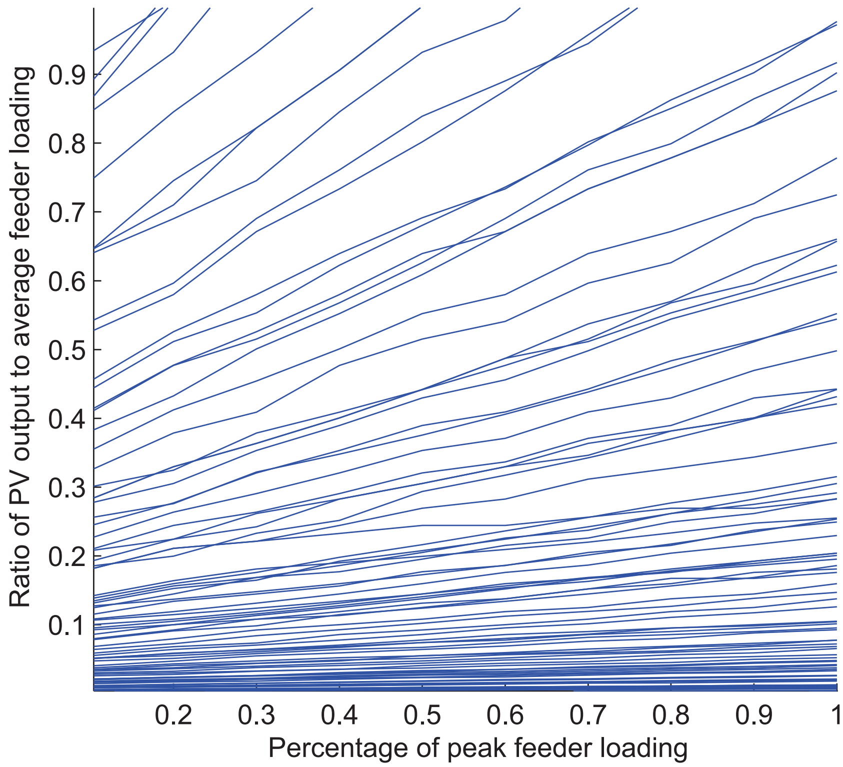

Figure 3.7: PV penetration level with varying feeder loading

slopes, which indicate that using the storage devices to increase the feeder minimum loading is more cost-effective on the feeders with larger slopes than the ones with smaller slopes.

The slopes are affected by many factors. When the original peak feeder loading is higher, more PV can be supported during peak but not so during the minimum loading period (valley), so the slopes tend to be higher. When the overall feeder impedance is higher, voltage drops more quickly in case of more loading or rises more in case of high PV output, so slope is higher. Therefore, storage option is the best for feeders with high impedance and low load diversity.

3.5 Summary

Various stakeholders in the de-regulated electricity market have been discussed, focusing on their roles related to the demand-side integration (DSI). The methodology of conducting the thesis has been elaborated with explanation of various software platform, the brief features of the standardised test networks, as well as the available practical data.

The formulation of the security-constrained economic dispatch (SCED) has been presented and simulated on a test transmission network using the GAMS software to show the nodal price variations. The demand profiles, transmission losses, and branch flow capacity limits have been modified in MATLAB software and fed into GAMS to automate the simulation process. The historical data of the New Zealand Electricity Market's bids and offers have been downloaded and modified to generate alternative dispatch scenarios using the vSPD software based on GAMS. The modification of the GAMS input GDX file has been done in MATLAB. Both the test network simulation and the ex-post analysis will be used to quantify the benefit of demand-side integrated resources reflected in the wholesale market trading mechanism.

The proposed modelling and simulation framework for a large-scale LV network has been implemented on a practical utility distribution low-voltage (LV) system to address the modelling issues of distributed energy resource (DER) penetration in LV networks. The distributor's entire LV network data in geographic information system (*GIS*) format have been processed using *MATLAB*, then converted into executable network models and scripted in *GridLAB-D* or *OpenDSS* syntax format for simulation. This practical modelling and simulation framework will be used for carrying out impact assessments for SG control, protection and economic integration, which can be in the context of PV, electric vehicle (EV), demand-side participation (DSP) and other DER studies.

Chapter 4

DSI by Distributor Pricing

4.1 Background

As mentioned in 2 Section 2.3, the electricity distribution businesses are regulated by government agencies to ensure optimal level of investment in the distribution network assets and fair allocation of investment costs to electricity users. Distributor pricing is the process of translating the cost information to price information, so that the consumers can pay for the usage of the distribution network assets. This chapter continues the discussion of distribution pricing methodology in general and extends the recent development of distribution pricing practice in New Zealand (NZ) to the pricing of various types of distributed energy resources (DERs), as mentioned in Section 2.1.

The distribution network peak capacity has been explained first. Load shaping strategies can be implemented using the non-network based solutions, such as controllable loads, demand response (DR) and electricity storage systems (ESS). The potentially high penetration level of small-scale photovoltaic distributed generation (PVDG) in residential networks may generate different patterns of distribution network peak, which may need to be supported by a range of distribution assets.

To demonstrate the process of optimal network reinforcement planning and peak capacity price derivation, the IEEE 123-node distribution test network has been simulated in this chapter as an example. It then investigates the case of controllable loads and the case of PV generation respectively, to adapt the pricing methodology to these DERs. The treatment of different DERs is proposed to be differentiated by their respective network support capabilities. For example, both controllable loads and ESS can defer network investment into the future and can support the distribution network to integrate PV generation. On the other hand, PV generation itself requires extra network asset support, so the treatment of PV without support infrastructure would be similar to the conventional load growth scenario.

Finally, this chapter concludes that the distributor pricing process provides the essential signalling to guide the integration of demand-side resources.

4.1.1 Regulatory and social considerations

As discussed in Section 2.3, the distribution network regulatory framework has been evolving since the electricity network was built. The objective of network regulation changes from investment cost recovery to consumer protection, and then from network delivery quality to the crossroad of the emerging SG paradigm. The current forms of distribution regulations carry the momentum of all the regulatory objectives in the past. With NZ distributor regulation as an example, the Commerce Commission of New Zealand's 'CPI-X-PQ' regime is a collection of the rate of return factor and network performance factor with distributor revenue cap. The effect of such a regime will still be in force for many years to come, concurrently with SG development. Therefore, the proposed distributor pricing model stems from the mainstream regulatory regime and aims to be applicable in the regulatory environment with the de-regulated market structure and SG initiatives.

It is anticipated that the distributor regulatory framework will adapt to the accelerating pace of the SG investment, which will see more elements added to facilitate the SG investment. One recent regulatory development by the Electricity Authority of New Zealand at the time of writing this chapter, is the 'model use-of-system agreement' for contractual arrangements between the retailers and distributors, so that the rights to develop controllable loads are made clear, and the communication protocols are standardised. It is expected that the standardised contractual arrangement will promote retail competition by enabling a differentiated distribution service and facilitate the development of non-network based solutions, such as demand management and distributed resources. The other regulatory development is the publishing of the 'principle-based distribution pricing methodology' by the Electricity Authority, which aims to promote subsidy-free, efficient, responsive and transparent distributor pricing structures transactionally equivalent to all retailers. The five principles are guidelines for distributors of various sizes to develop their own distributor pricing structure suitable for their network conditions. Therefore, the distributor pricing model developed in this chapter also aligns well with the five principles.

4.1.2 Major contributions

In this chapter, the preliminary feeder current and voltage results have been obtained from the unbalanced three-phase distribution load-flow calculations by using the open-source software GridLAB-D. A Mixed Integer Non-linear Programming (MINLP) formulation has been used in the optimisation of distribution feeder reinforcement planning considering the voltage and current constraints, which is then solved using the General Algebraic Modelling System (GAMS) software. The output of the optimisation establishes the network investment cost deferrable values when DERs are considered.

The distributor pricing approach based on the deferred network investment costs has produced pricing information that resembles the market mechanism depending on how many controllable-load owners sign up to provide the services [142]. The extended distributor pricing models in this chapter can be readily applied to differentiate customers based on their network usage and their support capability [143]. The distribution pricing model was modified to adapt to the high penetration level of PV, which is an emerging trend happening in distribution networks [144]. It is part of the GREEN Grid project outcomes, aiming to provide the government and industry with methods of integrating renewable energy in New Zealand.

4.2 Modelling of distribution network peak capacity

The core business of an electricity distributor is the management of distribution assets to serve the peak customer loading. On the level residential network with a distribution transformer serving a few households, the household loads are not all drawing power at the same time. Therefore, the loading seen by the distribution transformer is aggregated by multiple devices with the diverse load patterns. The peak loading can be referred to as the total loading after diversity. At the interconnection points to the transmission grid, the distribution network peak can be defined as the coincident peak demand (CPD), which is the sum of all aggregated loads at the grid interconnection point or grid exit point (GXP) that is coincident with the transmission grid peak. It can also be defined as the anytime maximum demand (AMD), which is the maximum aggregated load level recorded at the GXP during any time period.

4.2.1 Shaping the traditional network peak loads

Traditionally, distribution network peaks are governed by customer usage patterns, because the combination of residential and commercial loading tends to have established loading patterns and agricultural loading has a seasonally varying pattern with irrigation demand. Distribution network assets outside the peak periods are not fully utilised, so they are left to cool down in preparation for the next peak.

As opposed to building more distribution lines or upgrading the transformer capacity to meet the increasing peak loads, some DERs are capable of shaping the network peak by shifting their loads to the network valley, so that the investment costs of reinforcing the distribution network can be deferred to the future or even be saved.

Controllable loads such as thermostatically controlled load (TCL), electricity storage systems (ESS) and automated demand response (ADR) are examples of non-network based distribution solutions, which provide another set of tools for electricity distributors to maximise return on capital investment and to improve asset utilisation rate. Controllable loads also provide more system reserve for the transmission network operator. Electricity retailers who own controllable loads can reduce wholesale purchase payments or reduce transmission tariffs when the transmission network is congested.

The rights to develop and control controllable loads are clarified in a contractual agreement, such as the 'model use-of-system agreement', so that either distributors or retailers can receive the benefit of using controllable loads. The customers enter into the contract that allows some of their appliance loads to be controlled, such as heating or cooling appliances. Using controlling and signalling equipment that operates under the standardised communication protocols, either distributors or retailers can coordinate controllable loads. During normal operation, the loads are controlled according to the contract agreement. However, the system operator usually has a higher priority to use the controllable loads when there is a grid emergency.

4.2.2 Network hosting capacity of photovoltaic generation

As the cost of small-scale rooftop PVDG declines, the penetration level of PVDG in the distribution network will gradually increase. Contrary to the peak load planning in distribution networks, PV peak output usually does not coincide with peak load. When the total output of PVDG exceeds the total loads, voltages at the end of the distribution line can rise due to the resistance-dominant nature of the lines. The network-based distribution solution is to reinforce the distribution lines or to add voltage regulators.

Traditional loads are variable in nature, so the substation transformers serving a region of customers are usually equipped with an on-load tap changer (OLTC) to automatically change the voltage level according to variable loadings. Distribution transformers serving a small number of customers may or may not be equipped with such OLTC. When PV penetration level is low, the variable output can be handled by the existing network-based solutions, such as a transformer with or without the OLTC. When the penetration level increases, the output variability exceeds the existing design capability, so the network also needs to be reinforced.

The network hosting capacity of PVDG refers to the inherent capacity of the distribution network to integrate PV without resorting to other distribution solutions. When the PV hosting capacity is exceeded, the cost of line or transformer upgrading is mainly caused by PV output while not all consumers own PV generation. Therefore, PVDG becomes another factor to be considered in the network-based investment cost allocation process, which will be discussed in this chapter later.

Alternatively, non-network based distribution solutions can also support PV integration and defer the investment costs of expanding the network PV hosting capacity. ESS is commonly considered as the companion equipment to PV integration, but the cost of ESS increases the package cost of PVDG and ESS making PVDG otherwise less economical. In this chapter, a distinction has been drawn between PV generation and PV support infrastructure. Therefore, it is argued that whoever owns the non-network based distribution solution should also be compensated for the network support benefit accordingly.

4.3 Distributor pricing methodology

Figure 4.1 provides an overview of the process to derive the distributor pricing structure, with the cost allocation process in the lower part. The upper part is the optimal network planning process, which is the industry practice called the optimised deprival valuation (ODV) approach and prescribed by the competition regulator in NZ [145]. In the ODV approach, network configuration, capacity and engineering are systematically tested against optimisation criteria to find the most cost-efficient network design in an incremental fashion.

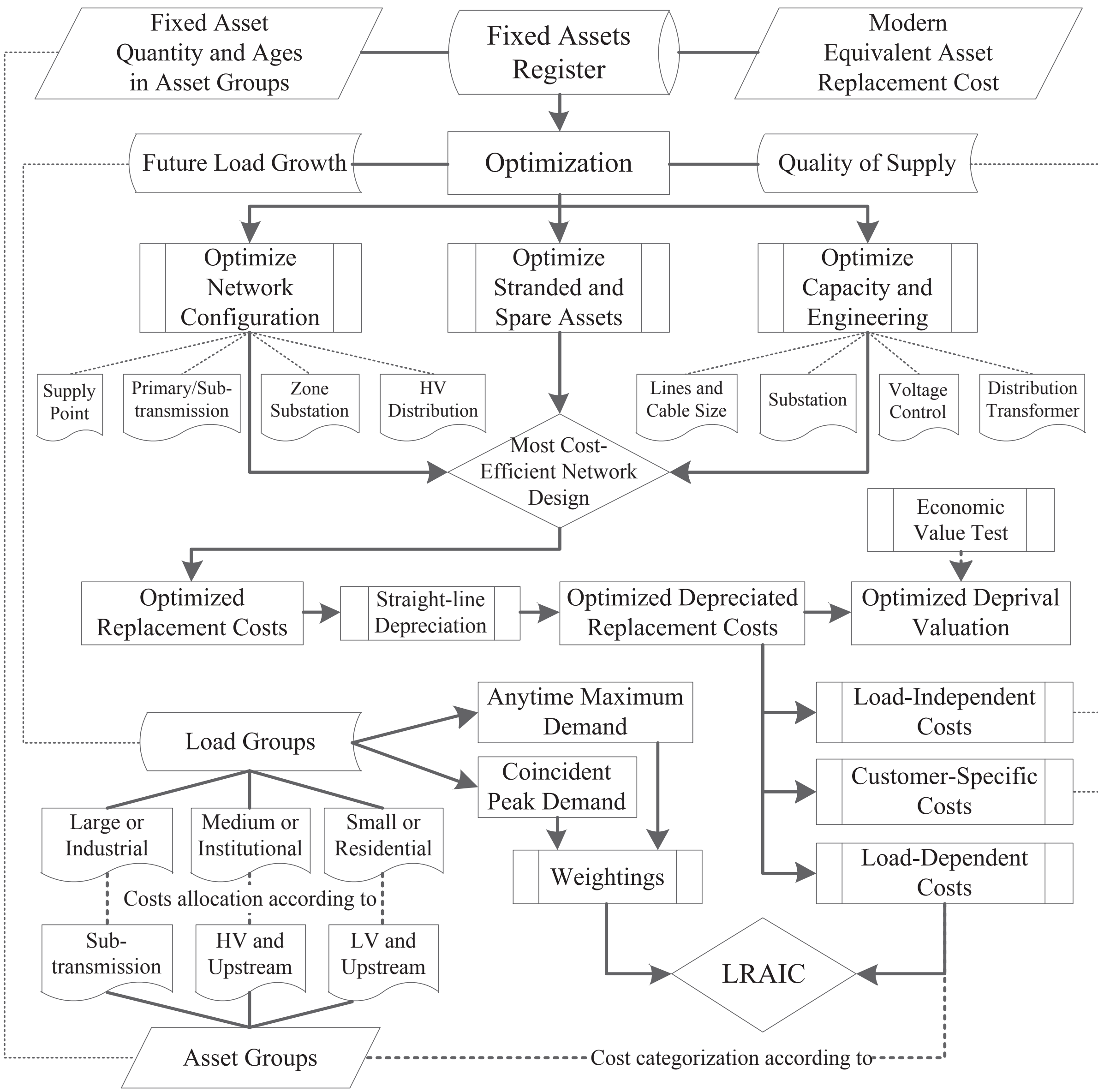

Figure 4.1: Flowchart of deriving distributor pricing structure

4.3.1 Optimisation formulation for network reinforcement planning

An optimisation formulation presented in this section provides the basis of deriving the total investment costs of future network reinforcement. The formulation can be solved in GAMS using Mixed Integer Non-linear Programming (MINLP). If the problem is difficult to solve, discrete requirements can be relaxed to use the Relaxed Mixed Integer Non-linear Programming (RMINLP). The optimisation formulation in this chapter is performed only for the process of determining feeder conductor types and sizes based on current profiles during peak loading, as an example of the optimal network planning process.

Objective function

The objective is to find the most cost-effective design, as if the network is notionally downsized to determine the total costs of future network reinforcement in the form of long-run incremental cost (LRIC)

$$min \sum_{f \in \Omega_{f,p}} \sum_{p \in \Omega_{f,p}} \sum_{s} C_{p,s} \cdot (1 + D_f) \cdot S_{f,s} \tag{4.1}$$

where

- $C_{p,s}$ is the conductor replacement cost for conductor f,
- p is the feeder conductor type,
- s is the feeder conductor size,
- $\Omega_{f,p}$ is a binary matrix parameter specifying the type is p for feeder conductor f, if the element in the matrix has a value of 1, and 0 otherwise,
- D_f is a binary variable vector indicating Feeder f needs reinforcement if value is 1, and 0 otherwise, and
- $S_{f,s}$ is a binary variable matrix indicating the chosen size for each feeder conductor, which 1 means feeder conductor f is size s, and 0 otherwise.

Constraints formulation

The above objective function is subject to the following constraints.

Firstly, designed feeder ampacity must be able to support future feeder current flow, while considering the peak capacity margin, L_I. Such margin is usually reserved to handle unexpected loading, or during feeder switching process to handle the extra loading from the neighbouring feeders. The margin can be determined in reliability assessment with feeder switching and reconfiguration using Monte Carlo analysis

$$\sum_{p \in \Omega_{f,p}} \sum_{s} M_{p,s} \cdot (1 + D_f) \cdot S_{f,s} > \frac{I_f \cdot (1+g)^y}{L_I} \cdots \forall f \tag{4.2}$$

where

- L_I is feeder conductor peak capacity margin,
- $M_{p,s}$ is the feeder conductor ampacity,
- g is annual load growth rate,
- y is the number of years until required to reinforce, and
- I_f is the feeder current at peak loads, which can be obtained by running unbalanced three-phase load-flow using GridLAB-D software.

Secondly, the chosen conductor size must have reasonable limit on voltage drop per unit length of feeder conductor, L_V

$$\sum_{p \in \Omega_{f,p}} \sum_{s} \sqrt{3} \cdot R_{p,s} \cdot I_f \cdot (1+g)^y \cdot S_{f,s} < L_V \cdots \forall f \tag{4.3}$$

where

- L_V is limit on voltage drop per unit length of feeder conductor, and
- $R_{p,s}$ is the conductor resistance per km.

Lastly, because $S_{f,s}$ can only have value of 1 or 0, the following equation restricts each feeder conductor to have only one conductor size

$$\sum_{s} S_{f,s} = 1 \cdots \forall f \tag{4.4}$$

and to have only one type, $\Omega_{f,p}$ also has this similar restriction.

4.3.2 Deriving distributor pricing structure

Valuation of Fixed Asset Base

Solving the above produces the notionally optimised feeder replacement plan. On the one hand, instead of using the actual amount of feeder replacement costs, the notionally optimised replacement costs (ORC) are substituted in asset base valuation and straight-line depreciation method is then applied

$$ODRC = ORC \cdot \frac{RL}{TL} \tag{4.5}$$

where

- ORC is the notionally optimised replacement costs,
- TL is total life of the asset,
- RL is remaining life, and
- $ODRC$ is the optimised depreciated replacement cost.

On the other hand, for reinforcement in the near future, ORC of these feeders are brought forward to the present value, ORC_{pv}

$$ORC_{pv} = ORC \cdot \left(\frac{1+CPI}{1+WACC}\right)^{y} \tag{4.6}$$

where

- ORC_{pv} is ORC brought forward to the present value,
- CPI is the average inflation rate used to track asset replacement costs in the future, and
- $WACC$ is the weighted average cost of capital or the discount rate in a financial sense to treat future investment as the value at present.

Finally, the total $ODRC$ in the asset group is the sum of individual $ODRC$ of network fixed assets, which is the LRIC of future network incremental reinforcement. Other asset groups, such as subtransmission networks, zone substations, low voltage feeders and distribution transformers, can follow this similar methodology to respectively determine the total $ODRC$ for their asset groups.

Revenue reconciliation and pricing structure

The long run average incremental cost ($LRAIC$) pricing methodology [146] differs from $LRIC$ slightly, which does not strictly allocate the incremental fixed asset costs to the particular customers who cause the network congestion, so it is less complex to understand and less costly to implement in practice. The $LRAIC$ method categorises the fixed asset costs (capital costs) into asset groups according to different voltage levels, then grouped fixed asset costs are assigned to the corresponding load group (such as residential, commercial or industrial) that utilises the asset group's equipment as well as all upstream equipment. Day-to-day operational costs on the other hand are not related to demand growth, whose allocation can still be averaged across all customer load groups.

To establish the link between costs and prices, one of the methods is to track and control the total distribution revenue earned by each distributor, so that their distributor businesses can be regulated by government agency. Target revenues to be collected, TR, reflect the $LRIC$ of feeder replacement and reinforcement. The $LRAIC$ is then calculated by

$$LRAIC = \frac{TR \cdot w_{peak}}{CPD} \tag{4.7}$$

where

- TR is the target revenue,
- w_{peak} is the weighting of TR for conductors that is load-dependent, and
- CPD is the coincident peak demand that measures the load group demand at the same time as the network peak demand.

Load-independent costs and other customer specific costs, such as day-to-day operational costs, can be recovered by volume-based price, VP

$$VP = \frac{TR \cdot w_{ind}}{ES} \tag{4.8}$$

where

- VP is volume-based price,
- w_{ind} is the weighting of TR for poles that is load-independent, and
- ES is total energy served in the year.

4.3.3 Modifying distributor pricing structure for DERs

Pricing of controllable loads based on deferred investment value

As opposed to constructing new lines or transformers when existing assets have reached the designed peak loading, non-network based solutions, such as controllable loads, provide alternative solutions to meet the growing demand. The distribution network planner can factor in the available controllable loads and develop alternative feeder reinforcement plans, which may require less reinforcement or replacement in the current regulatory period. This implies that notional savings, SV, can be achieved by distributors, compared with the feeder reinforcement plan without considering any controllable load

$$SV = DEP + ORC_d \cdot \left[1 - \left(\frac{1+CPI}{1+WACC}\right)^y\right] \cdot WACC \tag{4.9}$$

where

- SV is the notional saving,
- DEP is the yearly depreciation value of the delayed feeder reinforcement costs, and
- ORC_d is the delayed capital expenditure that would otherwise be included in the present regulatory asset base instead of y years later.

The savings should be attributed to the reduced peak loads, so the daily rebates, RB, are calculated as

$$RB = \frac{SV}{\Delta CPD \cdot 365} \tag{4.10}$$

where

- RB is the daily network tariff rebate, and
- ΔCPD is reduced coincident peak demand due to controllable loads.

Controlled energy usage is most likely shifted to another time period, so the effect on VP is assumed to be minimal.

Pricing of PV installations without support infrastructure

Distributed PV and wind generation by themselves are not considered as distribution solutions due to their variable nature; rather they should be counted as negative loads requiring delivery services by electricity distributors. Hence high PV output with low loading scenarios need to be simulated as one of the worst cases, together with the traditional planning worst-case scenario of peak loading.

The constraints of the optimal network reinforcement planning can be easily modified for the scenario of high PV penetration. The reverse current flow at a given PV penetration level, I'_f, can be compared with the peak loading current I_f. The larger one can substitute I_f and the corresponding projected PV growth rate, g', can substitute g if the larger reverse current flow is used. The limit on voltage rise per unit length of feeder, L'_V, can substitute L_V if the reverse current flow is larger than peak load current flow.

Solving the optimisation problem again then produces the optimised feeder reinforcement plan considering both peak loading and high PV penetration without any support technology.

To calculate $LRAIC$, two weightings, w_{peak} and w_{pv}, are used

$$LRAIC = \frac{TR \cdot w_{pv}}{NCPV} + \frac{TR \cdot w_{peak}}{CPD} \tag{4.11}$$

$$w_{pv} + w_{peak} + w_{ind} = 1 \tag{4.12}$$

where

- w_{peak} is the weighting of TR for conductors that is load-dependent,
- w_{ind} is the weighting of TR for poles that is load-independent,
- w_{pv} is the weighting of TR derived from conductors to support PV installations, and
- $NCPV$ is the total installed PV capacity that does not coincide with peak demand.

This process forms the base case (combined worst case) of calculating the $LRAIC$, so that other non-network based distribution solutions including PV support technologies can be benchmarked against the base case to derive their respective prices.

Pricing of PV integration and support infrastructure

Factoring PV installations in the base case scenario with both high PV penetration and peak loading, the notional savings can be proportioned to obtain the daily network tariff rebate RB, which offsets the network peak tariff derived as $LRAIC$

$$RB = \left(\frac{w_{peak}}{\Delta CPD} + \frac{w_{pv}}{\Delta NCPV}\right) \cdot \frac{SV}{365} \tag{4.13}$$

where

- RB is the daily network tariff rebate,
- SV is the notional saving,
- ΔCPD is the reduced coincident peak demand, and
- $\Delta NCPV$ is the reduced non-coincident PV capacity.

However, as in Equation (4.8), the energy volume based price VP is inversely proportional to the total energy consumption served by distributor ES. As more energy is generated by PV, the total energy consumption ES served by the distribution networks will appear to decrease at the substation level. The effect is that VP per kWh energy consumption increases for all customers. But for PV generation owners, their total energy consumption volume have been offset by PV generation, only the non-PV-generation owners will be worse off.

To remove this type of cross-subsidy, the formulation of ES needs to account for energy export due to PV generation as well, so that VP does not only depend on energy consumption, but also adjust for customers who export energy at different periods.

4.4 Simulation and case study

4.4.1 IEEE 123-node test distribution network

Network input data and assumptions

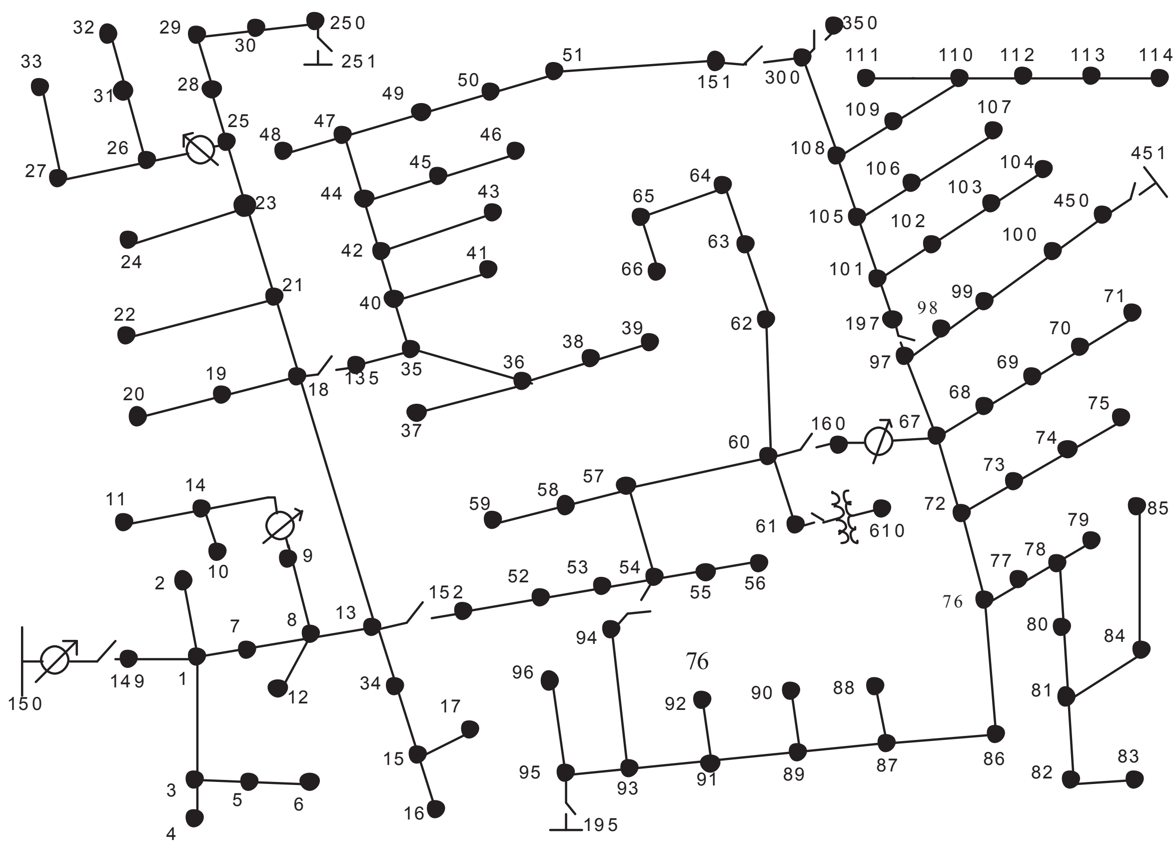

Figure 4.2: IEEE 123-node test distribution network

The IEEE 123-node test distribution network [147] as shown in Figure 4.2 is implemented for simulation, which has data on transformers, shunt capacitors, regulators, data on feeder length, configurations and spacings, conductor resistance per km, $R_{p,s}$, and feeder ampacity, $M_{p,s}$.

All loads specified are assumed to be peak values, but loading values are too large for distribution load-flow to converge properly due to line flow and voltage drop constraints. Therefore, average loading values are assumed to be half of the peak values. The original network is very unbalanced, so Phase-A loads at Node 1, 28, 68, 69, 70 and 71 are reallocated to Phase B, and loads at Node 45 and 46 to Phase C. Several feeders can be 'notionally' downsized from three-phase to single-phase, which are feeders between Node 55-56, 54-55, and 78-79. These feeders may be installed for other purposes, but from the view-point of load growth they appear to be over-built for load growth. Therefore, only the costs from the most efficient network design are accounted in ORC, excluding the over-sized part.

Feeder replacement costs and asset life

Assumed feeder replacement cost data is shown in Table 4.1, which is denoted by a matrix, $C_{p,s}$, with p being the feeder conductor type and s being the conductor size.

Table 4.1: Feeder standard replacement costs ($1000/km)

ACSR Size	***556***	***336***	***#4/0***	***#1/0***	***#2***	***#4***
$Cost_{O/H-4Wire}$	155	135	123	113	110	108
$Cost_{O/H-3Wire}$	149	126	113	102	98	96
$Cost_{O/H-2Wire}$	144	118	102	90	86	83
Cable Size	***2***	***1/0***	***2/0***	***250***	***500***	***1000***
$Cost_{U/G-Cable}$	268	286	296	310	322	344

All conductors and poles are assumed to have a standard life of 60 years, and have been in service for 45 years.

4.4.2 Optimal reinforcement and pricing structure with network based solutions

Current flow profiles with peak loads

Using GridLAB-D software, unbalanced three-phase distribution load-flow is run with peak loads, which produces current flow profiles for all feeders, denoted by I_j. The utilisation of feeder capacity is plotted in Figure 4.3 for all overhead lines and cables.

It can be seen that all 2-wire overhead lines and most of the 3- or 4-wire overhead lines have ample capacity for load growth in the next five years, with the exception of a few overhead lines operating close to the maximum capacity during peak loading.

However, a few 3-wire overhead lines have too much spare capacity, as shown in Table 4.2. The

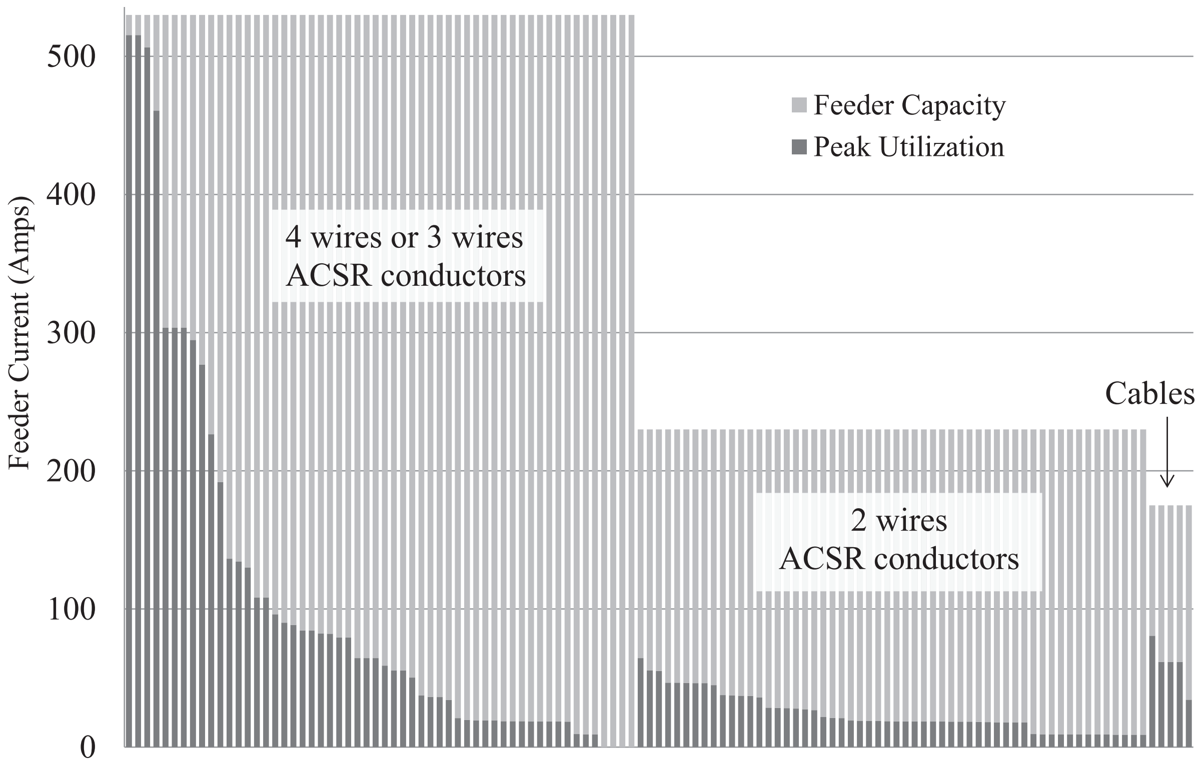

Figure 4.3: Utilisation of feeder capacity in IEEE 123-node network

size of these conductors was initially standardised to achieve simplicity and saving, but for cost evaluation purpose, they have been identified and treated differently in cost allocation process.

Table 4.2: Overbuilt feeder capacity in IEEE 123-node network

From Node	**To Node**	**Length (km)**	**Built Wires**	**ACSR Size**	**Optimised Wire(s)**	**Optimised Size**
55	56	0.08382	3	*336*	1	*#2*
54	55	0.08382	3	*336*	1	*#2*
25	26	0.10668	2	*336*	2	*#1/0*
35	36	0.19812	2	*336*	2	*#1/0*
78	79	0.06858	3	*336*	1	*#2*
47	48	0.04572	3	*336*	3	*#1/0*

Optimal network reinforcement plans for peak loadings

Since a feeder usually takes half-loading off the neighbouring feeder during emergency switching, the sustained loading on any feeder conductor will not exceed 75% of the maximum ampacity of the conductor. To be more conservative, a value of 60% is chosen for L_I in the case study, which is smaller than 75%. Given the voltage level of the test network is 4.16kV, L_V is 300 volt/mile for three-phase overhead lines, 100 for single-phase, and 200 for two-phase overhead lines and underground cables. These values of L_V are used in the right-hand side of the constraint equations, which indicate the worst cases of voltage drop. Practically, voltage drop will not be so significant as L_V. The optimisation identifies several feeder reinforcement plans for both 2% normal load growth annually and 5% high growth scenarios respectively.

Table 4.3: Planning of Group-1 feeders with 2% peak growth

Group	**From Node**	**To Node**	**Length (km)**
1	149	1	0.12192
1	1	7	0.09144
1	7	8	0.06096
1	8	13	0.09144
G-1 Replace	**ACSR Size**	**G-1 Reinforce**	**ACSR Size**
In 15 yrs	*336*	Now	*336*

In the normal growth scenario, if demand management or alternative supply switching is not implemented, immediate reinforcement should be undertaken to construct a parallel flow path along the set of feeders between Node 149-1, 1-7, 7-8 and 8-13, denoted as Group-1 feeders. Group-1 feeders, as listed in Table 4.3, will have have their reinforcement costs included in ORC calculation, with a newly commissioned service life of 60 years.

In the high growth scenario, as shown in Table 4.4, the replacement and reinforcement of Group-1 feeders require larger sized conductors, hence ORC is up-sized in this case. In addition, Group-2 feeders expect reinforcement in 10 years, which are feeders between Node 152-52, 52-53, 53-54, 54-57, 57-60 and 160-67. Hence ORC of these feeders are brought forward to the present value, ORC_{pv}, assuming CPI is 2% and WACC is 8%.

Table 4.4: Planning of Group-1 and 2 feeders with 5% peak growth

G-1 Replace	**ACSR Size**	**G-1 Reinforce**	**ACSR Size**
In 15 yrs	*556*	Now	*556*
Group	**From Node**	**To Node**	**Length (km)**
2	152	52	0.12192
2	52	53	0.06096
2	53	54	0.0381
2	54	57	0.10668
2	57	60	0.2286
2	160	67	0.10668
G-2 Replace	**ACSR Size**	**G-2 Reinforce**	**ACSR Size**
In 15 yrs	*336*	In 10 yrs	*336*

Revenue reconciliation and network tariff pricing

The total $ODRC$ in the asset group is the sum of individual $ODRC$ of network fixed assets. Referring to the modern equivalent asset replacement costs of feeders in Table 4.1, total $ODRC$ for feeders is \$398,249.80 in the normal load growth scenario and \$448,633.10 in the high one.

Other asset groups, such as subtransmission networks, zone substations, low voltage feeders and distribution transformers, can follow a similar methodology to determine the total $ODRC$ for their asset groups.

Table 4.5 lists the target revenues to be collected, which reflects the LRIC of feeder replacement and reinforcement.

Table 4.5: Target yearly distribution revenue for IEEE 123-node network

Growth Scenario	**Total ODRC (\$1000)**	**8% Return (\$1000)**	**Depreciation (\$1000)**	**Target Revenue (\$1000)**
2%	398.25	31.86	24.08	55.94
5%	448.63	35.89	24.32	60.22

The weighting of target revenue is load-dependent for conductors, w_{peak}, and is assumed to be

50%. The weighting is load-independent for poles, w_{ind}, and is assumed to be 50% as well [148]. The peak demand of the 123-node test network is 3490kW, so peak prices for the coming year are shown in Table 4.6. Average load is assumed to be half of peak load or 1745kW every hour, so total energy served is 15286.2MWh every year and volume-based prices are also shown in Table 4.6.

Table 4.6: Peak price and volume price considering load growth

Growth Scenario	**Recovered Revenue (\$1000)**	**Peak Load (kW)**	**Peak Price (\$/kW/day)**	**Volume Price (\$/kWh)**
2%	27.97	3559.8	0.0215	0.00179
5%	30.11	3664.5	0.0225	0.00188

4.4.3 Modification of pricing structure with controllable loads

Optimal reinforcement plan considering controllable loads

When each load point in the 123-node test network has a certain percentage of loads controlled, Figure 4.4 shows the reduction of the maximum phase current flows on Group-1 and Group-2 feeders in need of future reinforcement. The percentage of controlled peak loads shows the penetration level of controllable loads in the distribution network, which is assumed to be at an equal level across different portions of the network in the case study.

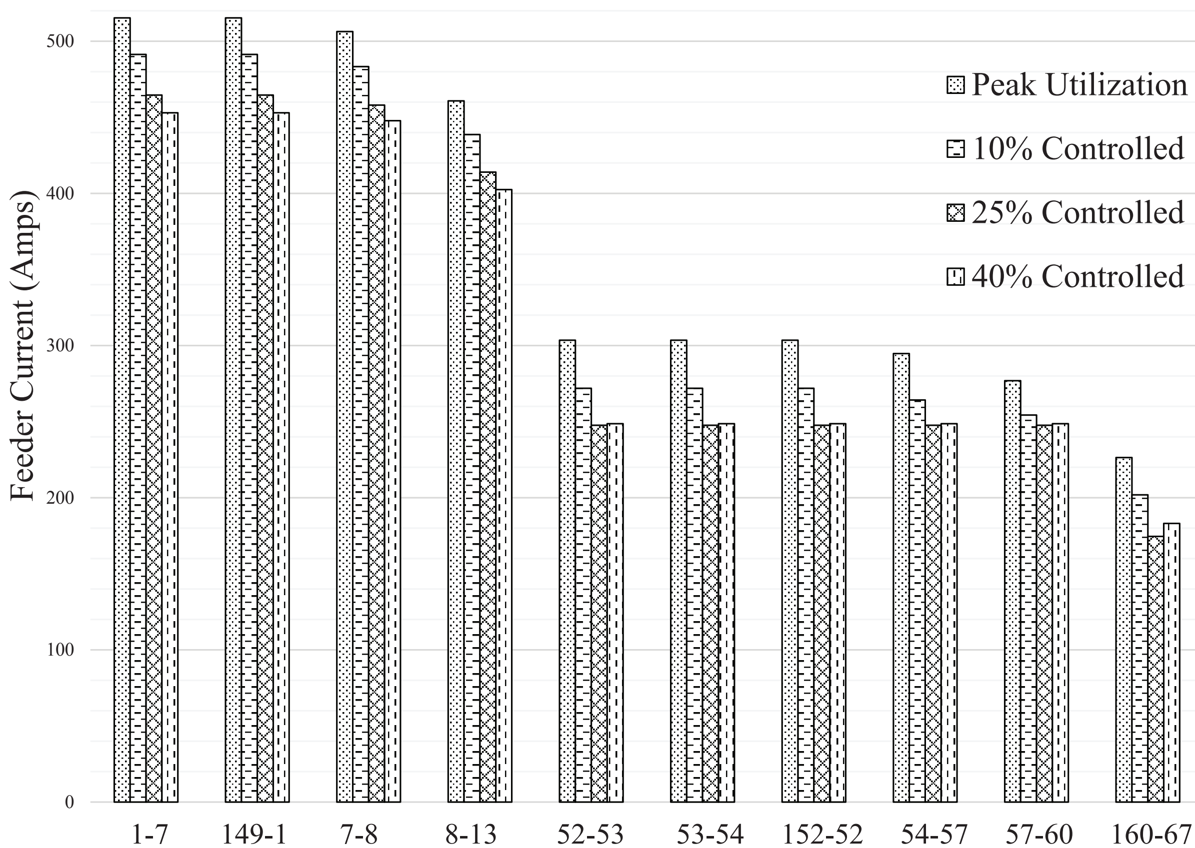

Figure 4.4: Feeder peak utilisation when a portion of loads are controlled

The distribution network planner can factor in the available controllable loads and develop alternative feeder reinforcement plans, as shown in Table 4.7.

For example, with controllable load penetration level at 10% of total coincident peak, Group-1 feeders, as identified in Table 4.3, can have reinforcement delayed to 5 years later under the normal

Table 4.7: Feeder reinforcement plans with controllable loads

Growth	***2%***	***2%***	***5%***	***5%***
Peak Demand	**Group 1**	**Group 2**	**Group 1**	**Group 2**
Uncontrolled	Now	–	Now	In 10 yrs
−10%	In 5 years	–	Now	In 15 yrs
−25%	In 10 years	–	In 5 years	In 20 yrs
−40%	In 20 years	–	In 10 years	In 20 yrs

load growth scenario, but the reinforcement is still imminent with 10% controllable load penetration level under the high load growth scenario.

Discussions of pricing structure with controllable loads

As shown in Table 4.8, peak price rebates can be offered to customers who provide controllable loads. The original peak price is $0.0215/kW/day without controllable loads, as shown in Table 4.6. The peak price rebate/discount on peak price is $0.01397/kW/day with 10% penetration level of controllable loads in the network, as shown in Table 4.8, which is a discount of $0.65 off a dollar from the original peak price.

Table 4.8: Peak price rebates for controllable loads

Growth	***2%***	***2%***	***5%***	***5%***
Peak Demand	**Saving ($1000)**	**Rebates ($/kW/day)**	**Saving ($1000)**	**Rebates ($/kW/day)**
−10%	1.817	0.01397	–	–
−25%	2.555	0.00787	1.812	0.00542
−40%	3.534	0.00680	2.543	0.00475

As more controllable loads are enabled, the savings are distributed among more controllable load providers, so the discount decreases to $0.405 off a dollar and $0.316 off a dollar, for controllable load penetration levels of 25% and 40% respectively. It resembles the market mechanism that increased supply of controllable loads decreases the rebate (price) payable to additional controllable loads. The case of 10% controllable load penetration level is not enough to achieve substantial saving in the high load growth scenario, because Group-1 feeder reinforcement is still commissioned during the current planning year. However, there may be other rebates provided by the distributor on savings achievable from deferring upstream assets, or by retailers who desire controllable loads.

If the rebates on peak prices are passed to electricity customers through retailer pricing packages, the retailer who actively develops or acquires controllable loads can appear to be more price competitive than other retailers.

4.4.4 Modification of pricing structure with high penetration of PV

Reverse current profiles considering high penetration of PV installations

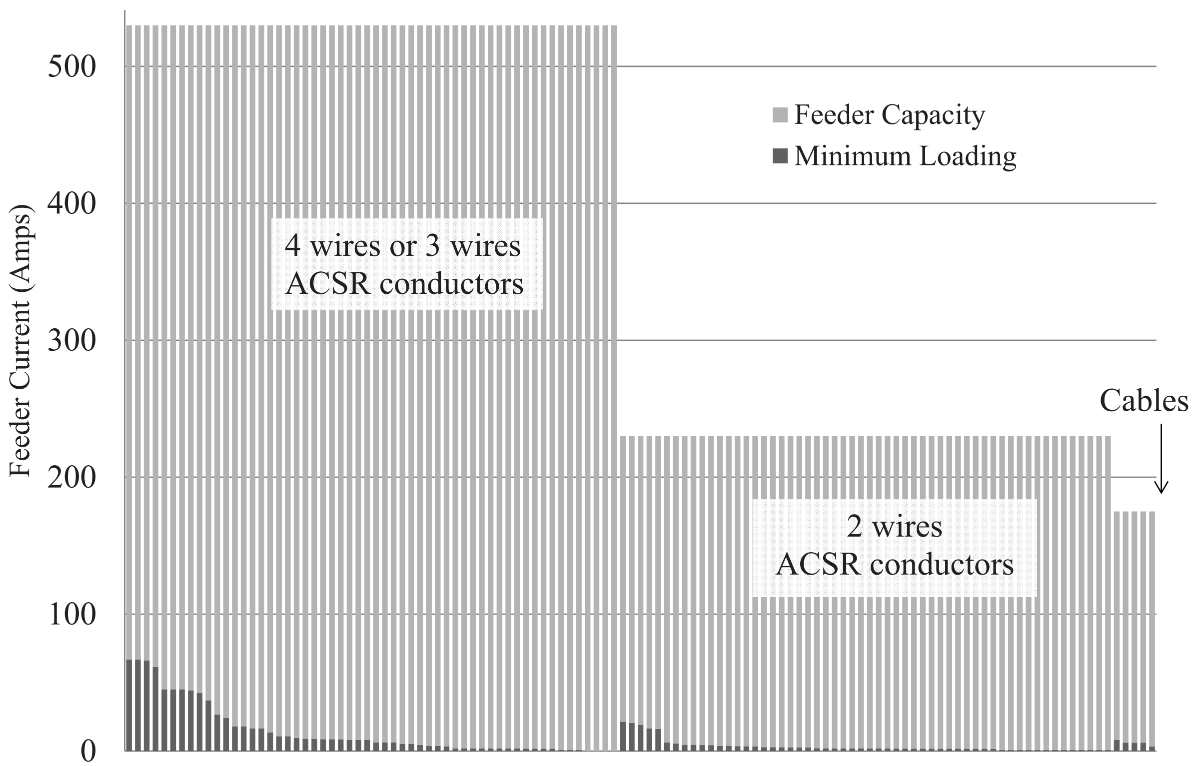

Figure 4.5: Utilisation with 10% of peak loading in IEEE 123-node network and no PV

PV output during working hours tends to not coincide with residential loads, so the high penetration of PV in residential networks may create voltage rise and reverse current flow. Since the worst case of high PV penetration is when the network loading is low, all peak loads of the IEEE 123-node distribution network are reduced to 10% of peak loading, as in Figure 4.5.

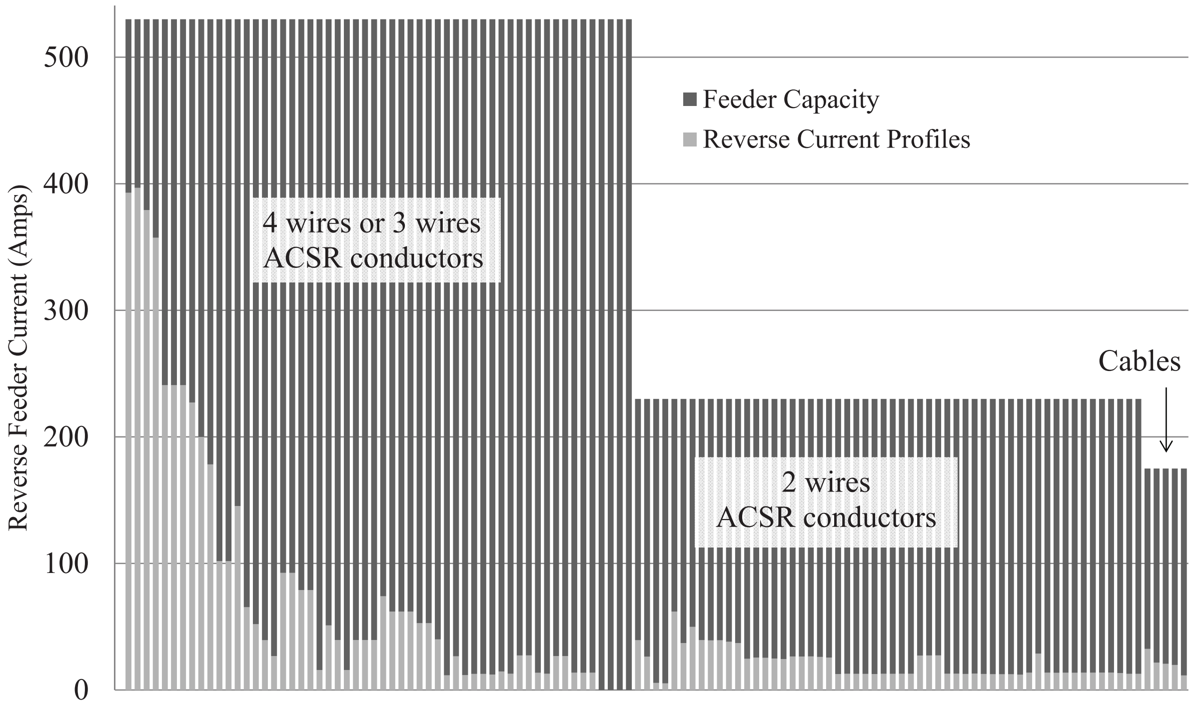

Figure 4.6: Feeder utilisation with 10% of loadings and evenly scattered 3300kW of total PV output

It is assumed that every ICP location has a PV installation and all PV installations are evenly scattered across all load locations. Without any network reinforcement, the maximum PV installations could have a total of 3300kW PV output or 95% of the total network peak loading. Roughly this is equivalent to have 35kW PV output at the loading point aggregated from several households. Figure 4.6 shows the reserve current profiles in this case.

By comparing the peak loading current profiles with the reverse current profiles during high PV output periods, the difference between the absolute values of current magnitude in both cases can be seen in Figure 4.7. If the voltage rise can be adjusted automatically by the transformer taps, most of the existing feeders with positive percentage values have the capacity to support PV growth. Feeders with negative percentage values start to experience more impact from PV growth than from load growth. The feeder from node 44 to 45 sees the largest difference of 8.4% more PV reverse current than peak loading current.

However, in a realistic PV penetration scenario, PV installations may concentrate in one area of the network, thus a part of the network may need reinforcement more urgently than the other. Rather than evenly scattering all PV installations, in the next scenario, nodes 28, 29, 30, 31, 32 and

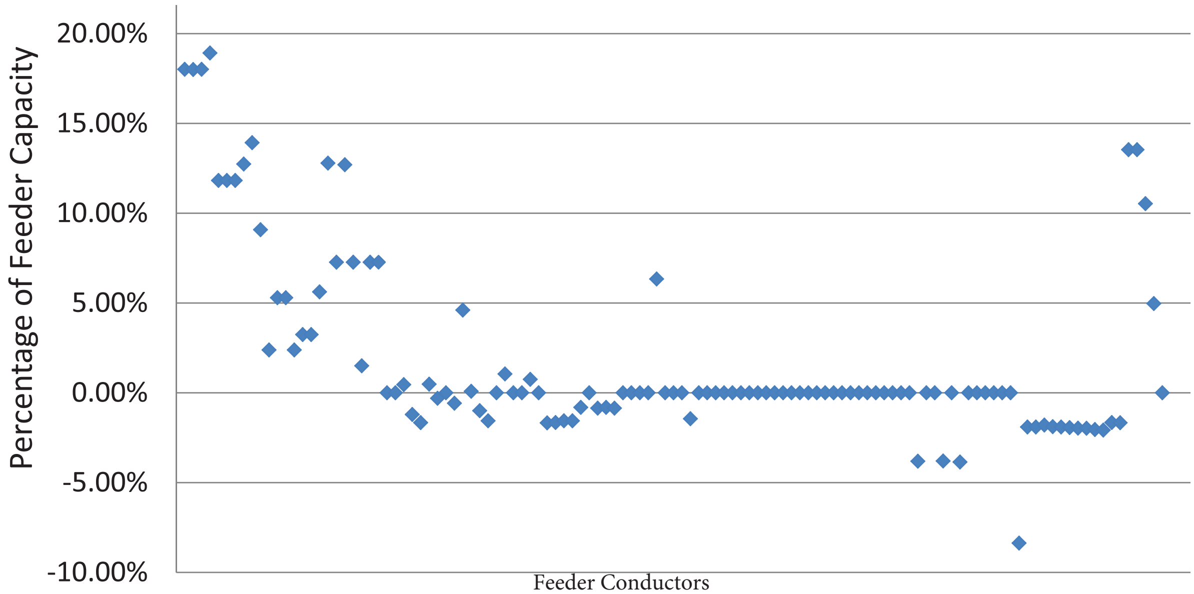

Figure 4.7: Feeder utilisation difference between peak loading and high PV output evenly scattered

33 are assumed to have no PV installation, but nodes 35, 37, 38, 39, 41 and 42 are assumed to have PV output doubled. With the total PV output being the same, Figure 4.8 shows five feeders have experienced 8% or more reverse current than peaking loading current, with one feeder from node 36 to 38 having the largest difference of 16.4% of the total feeder capacity.

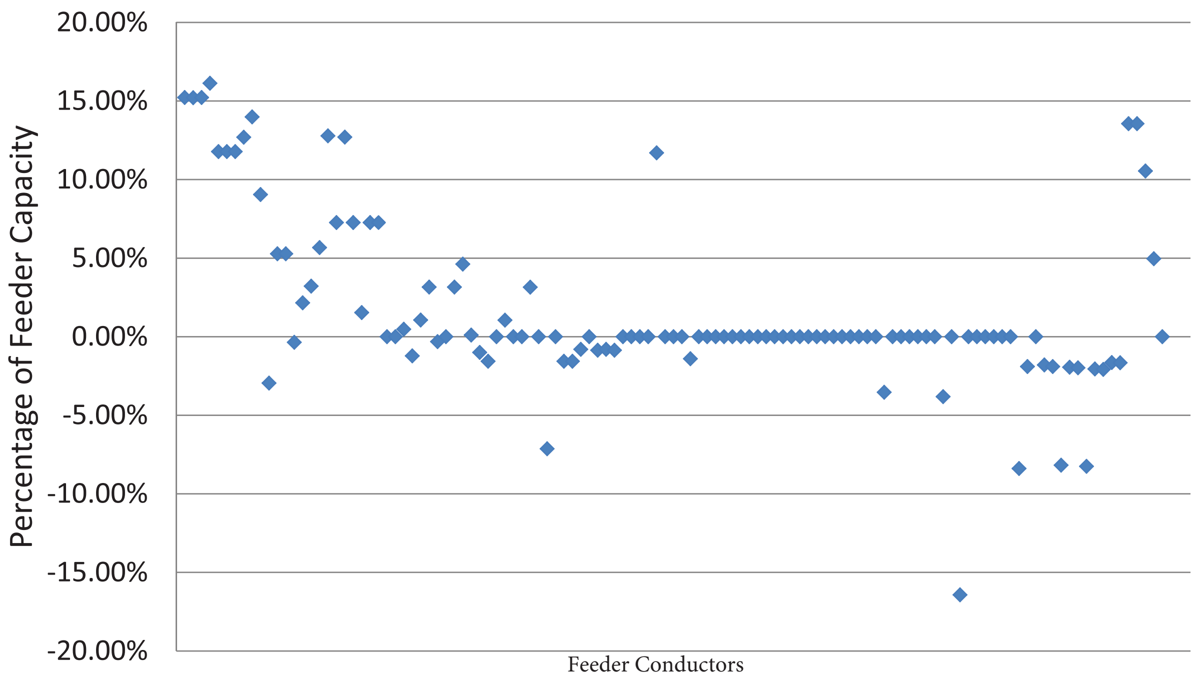

Figure 4.8: Feeder utilisation difference between peak loading and concentrated PV output

Discussions of pricing structure with PV

In the scenario with concentrated PV installations in the area of nodes from 35 to 42, the feeder from node 36 to 38 and the Group-1 and Group-2 feeders from Table 4.4 are all expected to be reinforced in 10 years. Table 4.9 shows the slightly increased target revenue in the high load growth scenario with 5% PV growth rate, due to the future reinforcement of feeder 36-38.

Table 4.9: Target yearly distribution revenue considering high PV penetration

Original ODRC ($1000)	**Additional ODRC ($1000)**	**8% Return ($1000)**	**Depreciation ($1000)**	**Target Revenue ($1000)**
448.63	5.077	36.3	24.32	60.62

From Figure 4.8, 29 out of 136 feeders are in the negative value zone, which implies that 21.3% of the feeders are now serving the high penetration of PV instead of the peak loadings. Therefore, multiplying 21.3% by 50%, w_{pv} is 10.65%, and w_{peak} changes from 50% to 39.35%.

NCPV is the difference between the total PV output and 10% of peak loading. Since PV is assumed to only coincide with 10% of the loadings, it is assumed that imported energy from the network is 90% of the original ES. The exported energy due to PV generation depends on the number of sunny days, so it is assumed to be 60% of the original ES (219 sunny days out of 365 days in a year). ES will then become 150% of its original value due to both energy import and export.

Table 4.10: Peak price and volume price considering PV installations

Price Category	**Recovered Revenue $1000**	**Denominator Type**	**Denominator Value**	**Unit Price**
Peak	23.824	CPD	3664.5 kW	0.0178 ($/kW/day)
PV	6.486	NCPV	3098.55 kW	0.005735 ($/kW/day)
Energy import	18.186	ES	13757.58 MWh	0.001322 ($/kWh)
Energy export	12.124	ES	9171.72 MWh	0.001322 ($/kWh)

Compared to the high load growth scenario in Table 4.6, peak price drops for customers without PV installations from $0.0215/kW/day to $0.0178/kW/day, because only 39.35% of target revenue TR needs to be recovered for demand growth instead of the previous 50%. However, peak price increases slightly by $0.005735/kW/day of PV connection price, from $0.0225/kW/day to

\$0.023535/kW/day for customers with PV installations. This is because distribution networks not only support their load connections, but also support their PV integration and export services.

All customers now pay a lower volume-based price of \$0.001322/kWh instead of \$0.00188/kWh to import energy, but customers who own PV generation will also have to pay for the additional \$0.001322/kWh to export energy. Effectively this increases the volume-based price of net energy to \$0.002644/kWh, so the customers with PV generation are better off to balance the energy export and import by themselves.

The PV connection price can be waived if the PV integration support technology such as an ESS with enough capacity to remove NCPV is used. The net energy export and import can also be minimised. Therefore, owners of PV installations with PV support infrastructure can clearly benefit from only paying the peak price of load connection to the distribution network. Essentially, the ESS and similar PV support infrastructure has a price tag, which is the sum of the PV connection price per day, and energy import and export price per volume of energy.

4.5 Summary

Distributor pricing structure provides clear signals for the various types of DERs, which is central to the integration of these demand-side resources.

The incremental-cost based distributor pricing methodology reflects the nature of the network planning and reinforcement procedure. Instead of the traditional network based distribution solutions, such as upgrading lines or transformers, DERs as the non-network based distribution solutions are the alternatives in the planning process. By using the non-network based solutions, the avoided or deferred investment costs of reinforcing the network can be attributed to the customers who supply these resources by means of discount or rebate. The level of DER availability then determines the amount of discount or rebate, creating market-like mechanisms for DERs, such as controllable loads.

As the PV penetration level continues to increase, the distribution network requires additional network infrastructure to support the PV integration. If the costs due to PV penetration are borne by all customers regardless of PV ownership, non-PV customers will effectively cross-subsidise PV owners by paying for higher network charges while PV owners enjoying lower cost of energy. To remedy that, PV installations should be factored in the distribution planning process, which are treated as if PV installations are the peak loads to be served. The distribution planning optimisation process then identifies the network portions that need reinforcement due to PV penetration. The investment costs to support PV integration can then be allocated to the PV owners according to the overall network asset usage. The benefit of PV support technologies, such as ESS, can be quantified during the process, which is similar to having a price to guide the decision to size the capacity of ESS in support of PV as well as demand management.

Future work can include the identification technique to localise the weak feeders that require additional protection measures due to high PV penetration. In addition to the impact of PV growth on the feeder current flow during the normal operation scenario, protection studies will be carried out to identify network reinforcement for the abnormal operation scenarios with high PV penetration level.

Chapter 5

DSI by Differentiated Quality

5.1 Background

Electricity delivery quality encompasses many aspects of the electricity distribution services, such as continuity of supply, momentary interruption, frequency, power waveform quality, voltage limits and more. Delivery reliability in terms of supply continuity is the most basic delivery quality of all, which is deteriorating in many distribution networks around the developed countries due to asset ageing. In Section 2.2.3, reliability has been factored into the distribution network design and planning process. In Section 2.3, the performance based regulation specifically monitors the distribution reliability indices to ensure there are ample network investment made to properly reinforce and maintain distribution network assets.

However, due to technical barriers and social uncertainty, the reliability indices and other delivery quality have not yet been fully factored into the distributor pricing practice. Firstly, there is a trade-off between the investment costs to improve delivery reliability and the reliability costs of losing electricity supply, which means that the costs of a highly reliable network will be borne by all customers. Secondly, the reliability costs of losing electricity supply are estimated mostly by conducting surveys and the very coarse value of lost load (VoLL) has been used in network operation studies. Lastly, differentiating reliability in distribution networks is challenging because of the 'free-rider' problem that customers on the same feeder generally receive the same level of power availability.

As the penetration of distributed energy resources (DERs) accelerates, the network delivery quality does not have to be homogeneous on the same service feeder. For instance, the use of distributed generation (DG) or electricity storage systems (ESS) can dramatically improve the power quality and supply continuity of one or several households at additional cost. It will also become complicated to assess the delivery reliability if only the thermostatically controlled loads (TCLs) are interrupted without even being noticed by the consumers, as the other normal loads are still operating.

Therefore, this chapter proposes the concept of a 'reliability premium' (RP) through which the individual customer can indicate their reliability preference and then pay the network tariff accordingly. Next, the motivation of differentiating delivery service quality is explained before proposing the process flowchart for the involved entities. A load dispatch formulation based on the reliability premium is proposed to help conduct demand-side bidding and also to set a limit to prevent load control from being excessively used. The IEEE distribution system for RBTS Bus No. 2 is simulated and solved using the General Algebraic Modelling System (GAMS). Finally, the chapter concludes that the demand-side resources should be integrated by allowing service differentiation to meet the various customer needs through SG development.

5.1.1 Regulatory and social considerations

Wholesale market participation

To enable demand-side participation (DSP) in the New Zealand Electricity Market (NZEM), a recent change has been brought to the demand-side bidding, scheduling and dispatching process. The system operator now publishes a Price-Responsive Schedule (PRS) and Non-Responsive Schedule (NRS) to reflect how Demand Response bids affect the generator schedules. Customers can elect to receive dispatch instructions similar to generators and avoid paying a high price in this demand dispatch (DD) scheme.

DD is different from demand response (DR) in which there are strict load compliance requirements to ensure the loads can be dispatched similar to the generators. Therefore, DD in the electricity market around the world is mostly used by large industrial or commercial customers at the present day due to the administration cost and monitoring cost. The development of controllable load or automated demand response (ADR) is expected to enable more small-customers to participate in the wholesale market through aggregators, but it takes time and resources to build the supporting infrastructure and outfit home appliances for this requirement. Hence, it is proposed to bridge the existing gap by a pricing model or business model, enabling small customers to participate in a relatively simple way. The model is less dependent on customer monitoring and is practically feasible before the coming advanced infrastructure is built.

Retail market competition

Meanwhile, the barrier for residential customers to switch among retailers has been considerably lowered in New Zealand, which stimulates retail competition. Consumer awareness of their options to compare electricity prices has been increased. Retailers and generators in New Zealand are associated to have financial hedges against wholesale volatility, so the motivation is low for retailers to offer demand responsive products to small customers. Right now the retail competition mostly undercuts the profit margin of retailers by offering discounts to keep their customer bases, but it is arguable as to whether this prevailing form of retail competition is healthy and sustainable.

The other issue in the retail market is that there is little retail product design variation aiming to differentiate service quality or network reliability, because retail products' innovation and customisation largely depend on how distribution network pricing is determined. In the proposed participation model, distributors are assumed to be able to adjust the distributor pricing or network tariff according to the reliability preference of the individual customer.

Distributor pricing differentiation

In New Zealand, the distribution network regulator uses both the network asset base and reliability indices to ascertain the total allowable distributor revenue. The regulated network tariffs are then passed on to customers by retailers, so customers receive one consolidated monthly bill indicating the network and energy components. The issue with using the system level reliability indices in the investment decision making is that the problems associated with the design, topology and loading of a particular feeder can be overlooked. On the one hand, to achieve a very high level of reliability on some 'problematic' feeders, much more investment is required on these feeders. On the other hand, customers who are connected to the more ‘problematic’ feeders tend to have poorer service quality than others, but still pay the same network tariff. To address this issue, some argue that building less reliability into networks can improve overall welfare, instead of providing one level of high reliability to all consumers [149]. Others suggest that the reliability guarantee contract and network reconfiguration can help optimise network assets to partially address the problem [150]. Along with the use of DERs, particularly, electricity storage system (ESS), delivery quality differentiation becomes feasible. Overall, how and where network companies allocate their capital and labour resources can impact service quality, so it is more efficient and fair to factor in customer reliability preference to network investment and operation decisions.

5.1.2 Major contributions

System reliability indices and estimated reliability costs used by distributors in their network design, planning and investment are very coarse, which will not be suitable to indicate network operational status and performance when more DERs are integrated into the distribution system. It is proposed in this chapter that the reliability premium can be used to indicate the reliability reference of individual customers as well as the willingness to reduce consumption through the automated demand response (ADR). Essentially, the individual customer enters into a contractual reliability guarantee when signing up for any electricity retail package or electricity delivery service. Customers can explicitly express their different levels of reliability preference and adjust their network tariff payments accordingly. More granular reliability cost data coupled with more detailed load point reliability indices provide better data for distribution planners to conduct reliability-based distribution planning, and for regulators and investors to have better information to make decisions.

The distribution network operator also benefits from the granular reliability cost and indices. The participation model in this chapter using the reliability premium shows an example of using the granular reliability indices to operate the distribution system with controllable loads and participate in the wholesale electricity market [151], which is different from most of the existing approaches using system level reliability indices. It is demonstrated in [152] that some particular SG technologies, such as ground fault neutraliser (GFN) and ESS, have already seen its granular impact on reliability improvement and investment decisions in practice. It is expected that both price differentiation and quality differentiation will become feasible with SG development [143]. The proposed reliability premium based service delivery model does not discourage investment in more reliable networks, because the extra service quality built into the distribution networks can be 'sold' to the wholesale market through demand-side bidding if not desired by the 'free-rider' customers.

5.2 Modelling with load point reliability indices

Electricity networks are usually divided into protective zones for protection coordination and reliability design, so that the faulty zone can be isolated or detached from the remaining network. Using the zone branch technique, the total failure rate, $\overline{\lambda_{ij}}$ of the particular zone i and branch j is the sum of all equipment failure rates whose failure will result in only the operation of the isolating device of zone i, branch j [153]. $\overline{r_{ij}}$ is the average repair rate, which is the weighted average of the repair time of the individual components in the zone branch. As the transition from failure state to normal state can be mapped, to derive the steady state probabilities, the Markov chain is used to study the distribution network reliability [154]. The reliability indices of a customer connected to a load point distribution transformer can be evaluated by the reliability indices of the zone branch in which the distribution transformer is located. These load point reliability indices at customer level are more granular than the system reliability indices.

5.2.1 Reliability premium and network tariff

A service delivery model is proposed to be different from other models in which the formulation starts with the load point reliability indices. It is argued that the distributor regulation needs to consider that the right granted to the distributor to serve the loads in a region also accompanies the obligation to connect loads at a certain level of connection quality [155]. Hence, to differentiate delivery service quality among different customers, it is proposed that a payment named as 'reliability premium' (RP) can be charged in addition to the normal network tariff.

Charging a minimum network tariff, such as the $LRAIC$ mentioned in Chapter 4, to each customer comes with a connection service of minimum quality obligation. Individual customer n at load point m can specify the payment of reliability premium (RP). The amount of RP consists of interruption payment IP if the service is lost due to both natural causes and forced outage, and duration payment DP depending on how long the outage lasts. The amount of IP and DP are also adjusted by the following equation

$$RP_{m,n} = (IP_{m,n} + DP_{m,n} \times r) \times \lambda \tag{5.1}$$

where

- λ is the government regulator agency prescribed value of failure rate per year, and is a system level reliability index,
- r is the prescribed repair time, and is also a system level reliability index,
- $RP_{m,n}$ is the payment of reliability premium for individual customer n at load point m,
- $IP_{m,n}$ is interruption payment, and
- $DP_{m,n}$ is duration payment,

Therefore, distributors can collect the reliability differentiated tariff, RDT, from each customer, which is composed of the same minimum network tariff, $LRAIC$, but different payments of the reliability premium according to individual customer preference

$$RDT_{m,n} = LRAIC + RP_{m,n} \tag{5.2}$$

where

- $RDT_{m,n}$ is the government regulator agency prescribed value of failure rate per year, and is a system level reliability index,
- $LRAIC$ is long-run average incremental cost, or the minimum network tariff.

The following example numerically demonstrates the reliability premium calculation. Regulatory authorities may impose the minimum reliability requirement that the loss of service to any customer must not exceed 5 hours per year. Based on this requirement, for example, the planning process may produce an average incremental cost of \$96/kVA per year to reinforce the network peak loading. For a customer in the load group up to 15kVA, the incremental network charge is \$1440 per year. With a prescribed average load point failure rate of 0.5 per year and average repair time of 10 hours, a customer who chooses to receive a compensation package of \$10 for every recorded interruption and \$25 per hour for any service discontinuation should pay for the reliability premium of \$130 per year, or 9% extra payment on the minimum network charge.

Customers who choose to pay for a higher reliability premium will receive more compensation from the distributor in event of outages. Paying a higher reliability premium does not guarantee receiving a higher level of delivery service quality, but the direct financial penalty to the distributor may influence the company decisions to allocate more resources to address the problems, such as investing in SG automatic restoration, reinforcing the network sections, installing temporary storage devices, or dispatching repair crews in priority. Customers who choose to pay less but happen to be the 'free-riders' in a highly reliable network may have more instances of load control or device control to provide benefit for other stakeholders. For example, a retailer may use controllable load with demand-side bidding to achieve electricity wholesale purchase saving, or a distributor may use controllable load to manage network peak.

5.2.2 Process of integrating reliability premium

The detailed process of integrating the reliability premium in the current system [151] is illustrated in Figure 5.1. Customers, especially small residential customers, usually only deal with the service aggregators or retailers when they sign up for a retail service package. The retail service package may cover various DER services, such as giving away the rights of controlling certain appliances in exchange for bill discount or rebate. The control signalling and communication equipment installed in the customer premise may belong to the retailer or the distributor. In addition, customers can be offered different levels of delivery service quality. A customer who has PV and ESS can sustain a longer period of supply outage, so the customer may opt to receive a lower level of reliability and pay less reliability premium for higher network supply reliability.

Retailers or aggregators who work with the distributors can pass the aggregated information of reliability preference to the distribution network planner and operator. The reliability preference expressed in terms of detailed reliability costs can further improve the present-day network planning practice. Network reinforcement can be planned if long-term reliability needs are identified. Short-term reliability requirements can be addressed by DERs, such as temporary use of ESS.

To offset the costs paid for the forced outage or load control, savings can be derived from wholesale market bidding through DSP or DD. Advanced meters capable of interval metering and load controlling can be installed at the customer premise level. When the benefit of controlling a load exceeds the benefit of servicing the load during a particular interval, the load of the 'free-rider' customer or device can be controlled more frequently. However, to prevent certain 'free-rider' customers from being excessively controlled, granular feeder-level or customer level reliability records should be maintained.

In the following sections, a service delivery and load control model using the reliability premium concept has been formulated and simulated, which integrates both the controllable loads and reliability indices.

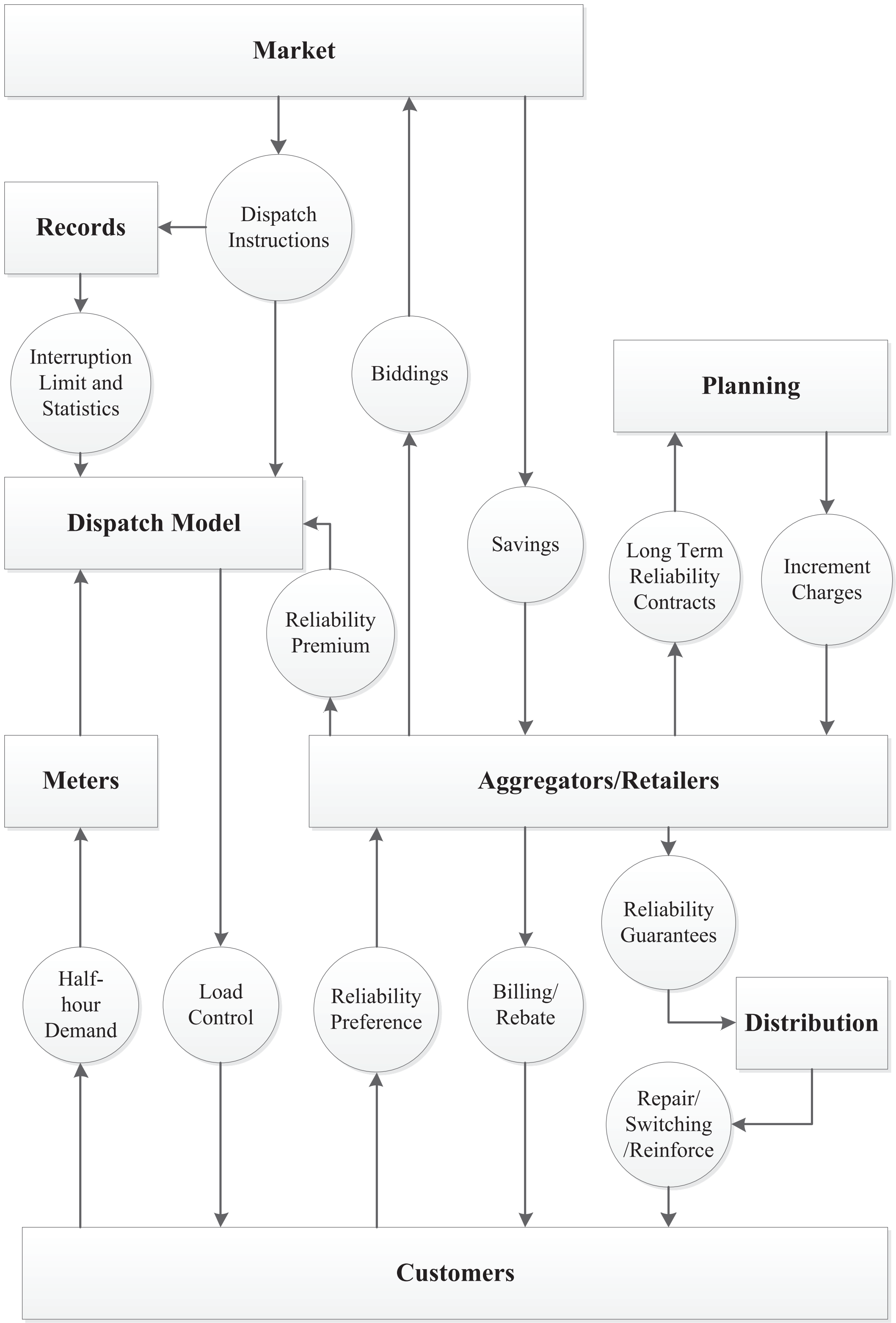

Figure 5.1: Processes of utilizing the reliability premium and load point reliability indices

5.3 Automated load control considering reliability premium

5.3.1 Objective formulation

The reliability premium based service delivery and load control model is formulated as a mixed integer optimisation problem with binary variables, which is solved using GAMS as well. The objective function is to maximise net benefit, NB, for the combined entity of energy retailers and distributors

$$max\ NB = WS_1 + WS_2 - TPC \tag{5.3}$$

where

- NB is net benefit,
- WS_1 and WS_2 are wholesale savings, and
- TPC is total penalty cost.

There are two major incentives derived from trading controllable loads in the wholesale market. The first part of the wholesale saving WS_1 is to avoid paying at at very high wholesale market price, P_{prs}, by responding to reduce the demand of an amount equal to $\Sigma\Gamma_{m,n} \times K_{m,n}$. However, because the demand is not served, both the retailer's energy revenue and distributor's network tariff are lost. The benefit of wholesale saving is offset by the retail price of P_{ret}

$$WS_1 = \Sigma\Gamma_{m,n} \times K_{m,n} \times (P_{prs} - P_{ret}) \tag{5.4}$$

where

- $\Gamma_{m,n}$ is the demand metered for customer n at load point m in the previous interval,
- $K_{m,n}$ is a binary variable, with value 1 being the customer controlled or device off in the current interval, and 0 being uncontrolled or device being on,
- P_{prs} is wholesale market price by responding to reduce the demand, and
- P_{ret} is the retail price including retailer's energy revenue and distributor's network tariff.

The second part of wholesale saving WS_2 is to pay less for all the uncontrolled load of a retailer, if the retailer responds to the system operator's instructions to reduce demand

$$WS_2 = \Sigma\Gamma_{m,n} \times (1 - K_{m,n}) \times (P_{nrs} - P_{prs}) \tag{5.5}$$

where

- P_{nrs} is the indicated market price without reducing the demand.

The direct penalty cost, DPC, is the sum of duration payments for actually controlling the loads, ignoring interruption payments in this formulation

$$DPC = \Sigma DP_{m,n} \times K_{m,n} \tag{5.6}$$

where

- DPC is the direct penalty cost, and
- $DP_{m,n}$ is duration payment for individual customer n at load point m if load is controlled.

The industry has been using the Value of Lost Load ($VoLL$) to coarsely approximate the interruption cost for average customers. The reliability premium can refine the interruption cost model, so that $VoLL$ represents the social cost of losing the electricity service and the reliability premium is the private cost. As discussed in the 'free-rider' problem, some consumers may elect to not participate in any of the compensation schemes, so for those customers, only the social cost of controlling their load is considered.

Therefore, the total penalty cost of load control is

$$TPC = \Sigma(DP_{m,n} + \Gamma_{m,n} \times VoLL) \times K_{m,n} \tag{5.7}$$

where

- $VoLL$ is the Value of Lost Load,

5.3.2 Constraints formulation

Two constraints are proposed in the differentiated service delivery model. The first constraint considers the strict load compliance requirement that is similar to the dispatch instruction of generators

$$\Gamma^{dd} = \Sigma\Gamma_{m,n} \times K_{m,n} \tag{5.8}$$

where

- Γ^{dd} is the exact load reduction has to be maintained according to operator instructions.

The second constraint imposes a limit on the allowed hours of load interruption every year for each customer load or device, AT, which can have different values depending on the nature of the load or device. For example, controllable loads such as controlled electric vehicle charging or hot-water cylinders may have a higher limit than other loads at the household level. The limits can be set based on outage records of individual customer and outage probabilities at the load point m

$$AT_{m,n} + \frac{K_{m,n}}{2} + \lambda_m \times r_m < AT \tag{5.9}$$

where

- λ_m and r_m are reliability indices at load point m, obtained using the zone-branch technique [153],
- $AT_{m,n}$ is the accumulated hour of interruption for customer n at load point m during the past 365 days, and
- AT is the limit on the allowed hours of load interruption every year for each customer load or device.

$AT_{m,n}$ can be modified on a seasonable basis as $AT'_{m,n}$ for a particular season to account for temperature, rain fall or storm activity variations

$$AT'_{m,n} + \frac{K_{m,n}}{2} + \lambda'_m \times r_m < \frac{AT}{4} \tag{5.10}$$

where

- λ'_m is the adjusted load point average failure rate in the particular season, and
- $AT'_{m,n}$ is the accumulated hour of interruption on a seasonable basis.

The voltage variations, network loss, reactive support, and distributed resources are not considered in this formulation.

5.4 Simulation and case study

5.4.1 IEEE RBTS distribution network Bus No. 2

The simulation is carried out using the data of the RBTS distribution network Bus No. 2 [156], as shown in Figure 5.2. The base case load point reliability indices for overhead lines are used, with disconnects, fuses, alternative supply and repairing transformers. The constraint used in the simulation is the yearly formulation. The penalty costs in terms of DP to be paid to individual customer in event of losing electricity service are assumed in the last column of Table 5.1.

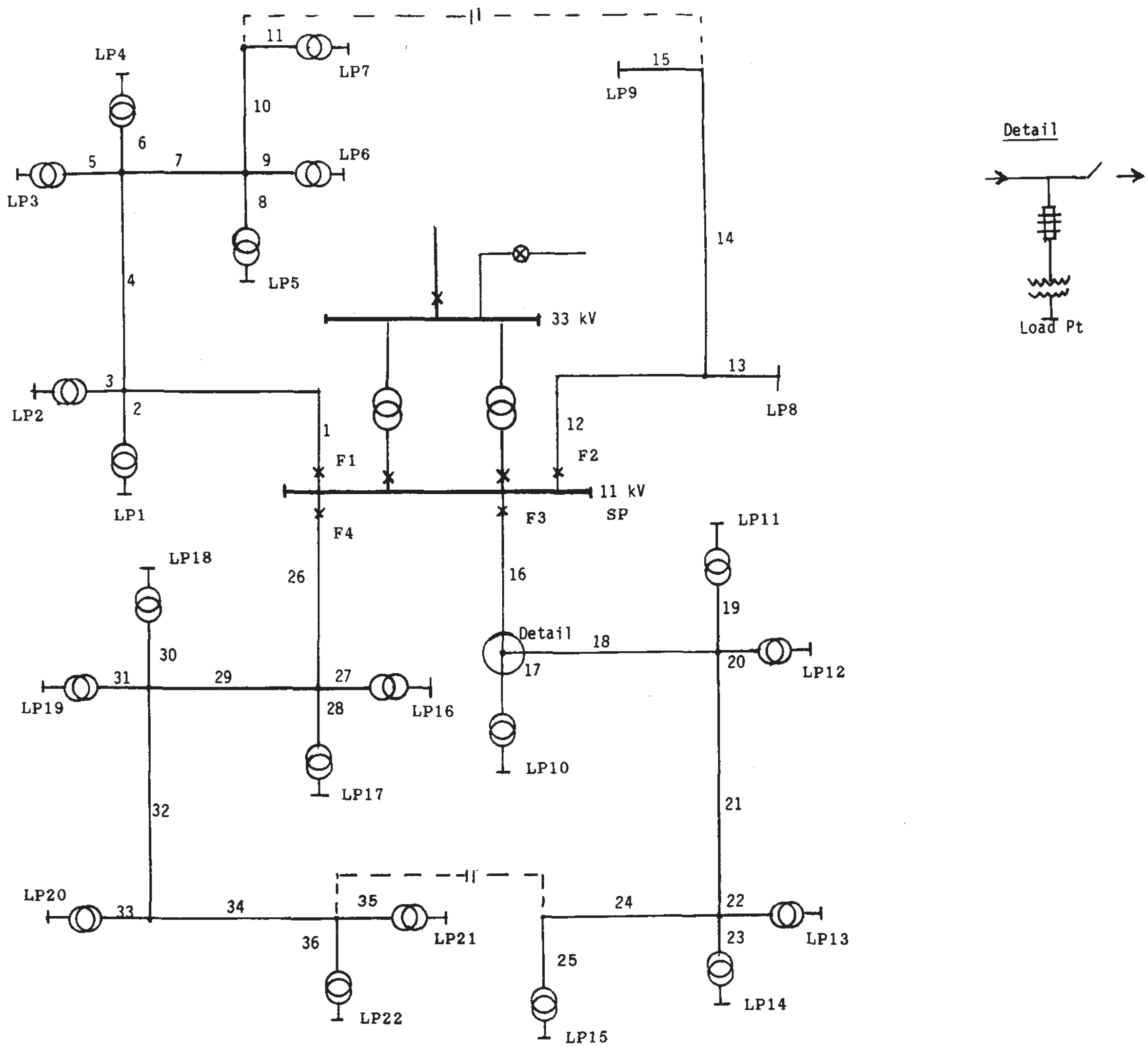

Figure 5.2: RBTS distribution network Bus No. 2

There are 1908 customers or devices in total, which have an average total demand of 12.291MW. The demand interval is half an hour to match the wholesale trading period. Retail price is assumed to be $350/MWh, including energy price and variable network tariff. The total allowed service lost hour is set to be 5 hours per year, starting with no accumulated disconnection hour, i.e. $AT_{m,n} = 0$. The total allowed service lost hour can be set higher for loads that are controllable and the customers have sold the controllable rights to either retailer or distributor according to their retail service contract. However, an equal number of 5 hours is used for all loads or devices in the simulation.

Table 5.1: Simulation data used as in RBTS Bus No. 2 distribution test network

Type	**Load point**	**Customer number**	**Metered demand**	**Compensation required**
Residential	1-3, 10, 11	210×5	2.55kW	50% none, 30% $25/h, 10% $50/h, 10% $100/h
	12, 17-19	200×4	2.25kW	
Industrial	8	1	1MW	$3000/h
	9	1	1.15MW	$5000/h
Government Institution	4, 5, 13	1×3	0.566MW	$1000/h
	14, 20, 21	1×3	0.566MW	$2000/h
Commercial	6, 7, 15	10×5	45.4kW	50% none, 30% $100/h, 10% $500/h, 10% $1000/h

5.4.2 Discussion of RBTS network implementation results

In the case study conducted on the RBTS distribution network Bus No. 2, the proposed optimisation algorithm tries to reduce the customer load or device load of the appropriate size starting from the one with the lowest penalty cost during each interval. Once the limit is reached for a particular customer, the load or device will not be selected to control any more. The algorithm then tries to select the next best load or device to reduce its load.

Load reduction triggering price level

With the social cost imposed as the $VoLL$, the wholesale non-responsive price, P_{nrs}, has to reach a certain level in order to trigger any load disconnection, as summarised in Table 5.2. The $VoLL$ can be considered as the safeguard for the minimum level of reliability standard, as a portion of the customers may not specifically set a higher or lower reliability target through their retail service contracts. Instead, these customers may opt to go for the default level of reliability as they currently are, so the $VoLL$ sets the bar for these types of customers. As the chosen $VoLL$ increases or the amount of load disconnection increases, the triggering price level requires higher non-responsive wholesale price to justify the load disconnection.

Table 5.2: Triggering non-responsive price levels for different VoLL values and load reductions

VoLL ($/MWh)	10000		20000	
Total load reduction (MW)	1	1	2	2
Triggering price level ($/MWh)	900	1700	1700	3300

Demand-side bidding aid

The DD scheme has been implemented in such way that the electricity usage quantity bids submitted every half an hour state the different wholesale responsive prices (P_{prs}) and the associated amount of load reduction at each price. If one bid is chosen to be dispatched by the system operator, the final payment price by the retailer will not exceed the price stated in the bid. Normally, the demand bidding curve must be constructed in a shape that is downward sloping with respect to the price. Therefore, the greater amount of load reduction, the lower responsive price a retailer is expected to pay. Retailers who submit the quantity bids of electricity usage at different wholesale responsive price P_{prs} levels must ensure the settled market price at least makes the load controlling break-even so that the savings from the wholesale market can cover the penalty costs paid to the interrupted customers. Table 5.3 shows the maximum level of price responsive bids required at different load reduction steps. For example, if the retailer is asked to reduce 1MW of load, the responsive price level the retailer should set in their bids must be lower than $1000/MWh.

Table 5.3: Break-even price responsive bids at various load reduction steps

VoLL ($/MWh)	10000			
Non-responsive price ($/MWh)	1800			
Total load reduction (MW)	0.5	1.0	1.5	2.0
Responsive price level ($/MWh)	1400	1000	600	100

Load control and interruption limit

In the service delivery and load control model, the lowest cost loads are usually chosen first to be disconnected if the accumulated hour of disconnection has not yet exceeded the limit. As an example shown in Table 5.4, when all customers in the network are assumed to have accumulated 1 hour of disconnection ($AT = 1$), the allowed hours of disconnection are exhausted for some customers who are receiving a lower level of reliability due to the inherent network design. As a result, the maximum responsive price level is lower in the case of $AT = 1$, so the gap between non-responsive price and responsive price is larger. The wholesale saving obtained is higher in the case of $AT = 1$ to justify the same amount of 1MW load reduction, reflecting the fact that the 'spare' reliability as a resource in the distribution network becomes scarce. The more expensive industrial loads that require \$3000/h in compensation must now be reduced, as the industrial loads still have some headroom in terms of accumulated interruption hours while the cheaper residential loads have exceeded the interruption limit.

Table 5.4: Effect of accumulated interruption hour on price responsive bids

VoLL (\$/MWh)	10000	
Non-responsive price (\$/MWh)	1800	
Total load reduction (MW)	1	
Accumulated interruption hour for all customers (h)	0	1
Responsive price level (\$/MWh)	1000	700
Load point	12,17-19	8
Load type	Residential	Industrial
Compensation required	None	\$3000/h

5.5 Summary

In smart grids, implementing controllable loads may adversely affect the delivery service quality at the granular customer level, but using electricity storage systems (ESS) can also selectively improve the service quality of some customers served by the same distribution feeder. The proposed payment of the reliability premium (RP) to the distributor is based on the load point reliability indices, which can be derived from the zone branch technique. Customers who choose to pay for the reliability premium as part of the network tariff are expecting to receive better service quality, and in turn indicate their reliability preference explicitly. Therefore, if these customers are located in the high-reliability portion of the network, their loads will not be controlled so often. If these customers are located in the low-reliability portion of the network, the distributor could implement network reinforcement or use temporary ESS solution to improve their service quality.

The proposed pricing and load dispatch in the wholesale participation model helps small customers easily participate in wholesale market trading based on their unique levels of reliability preference. The payment of the reliability premium can affect their load priorities in the load control dispatch algorithm and also the monthly rebates received from the wholesale market savings. The participation model integrates both wholesale and retail markets, which serves as a complementary tool for system operator, retailers, aggregators, distributors and planners to engage small customers.

The proposed service delivery and load control model encourages investment in a more reliable SG, as the reliability built into the network can now be controlled and adjusted for each individual customer through the use of SG technology such as automated load control and ESS. The extra reliability in the network can also be 'traded' in the wholesale market through demand-side bidding using load control as demonstrated in Section 5.4, if not desired by the 'free-rider' customers. However, retailers and distributors who seek to maximise net benefit by trading aggregated controllable loads in the wholesale market need to consider the reliability limit at the customer level in terms of accumulated interruption hours, or even more granular at the device level to differentiate the load types within a household.

Overall, distributors who enable more SG technology options should consider not only price differentiation but also service quality differentiation when engaging customers with various needs and preferences.

Future work can simulate the effect of other SG technologies such as distribution automation on the reliability performance. The priority of different reliability improvement options, such as cable replacement, battery installation or distribution automation can be optimised, considering the reliability premium in the formulation as well.

Chapter 6

DSI by Resource Availability

6.1 Background

As reviewed in Section 2.1, distributed energy resources (DER) are important energy and network solutions at the demand side for the network and grid operations in SG. The rooftop solar photovoltaic (PV) generation, the energy storage systems (ESS) and the plug-in electric vehicle (PEV) chargers start to appear in residential households. The thermostatically controlled load (TCL), such as water heating, space heating or cooling, or refrigerator, will be enabled to support the grid. The deferrable but non-interruptible load, such as dryer or washing machine, will also contribute to the procurement of demand response (DR) from the small residential users. Scheduling these DER devices to achieve the maximum operational benefit becomes an issue that needs to be addressed.

Section 2.2 has reviewed many approaches to optimally operating the distribution network with DERs. Chapter 4 addressed the demand-side integration (DSI) from the distribution planning and investment perspective. Chapter 5 focuses on the delivery reliability in DSI considering certain planning and operational matters. However, the gap still exists to reconcile the cost and benefit of all types of DERs from the network operational aspect.

The structure of this chapter is to initially present the challenges of operationally integrating demand-side resources from the regulatory and social perspectives. The proposed DER scheduling and pricing framework is then explained, followed by detailed formulation of the decentralised DER device modelling and centralised distributor scheduling. A small distribution test system was implemented to provide simulation results for the discussions of centralised scheduling. A larger test system is implemented to demonstrate the scale of device decisions that have been accommodated.

6.1.1 Regulatory and social consideration

Local distribution network conditions

Many DER scheduling approaches use the real-time wholesale market prices, but the wholesale electricity market structure is not available in many countries. Even in places where the wholesale market exists, such as the New Zealand Electricity Market, the locational marginal price (LMP) at the grid interconnection point gives an indication of the energy price offered by generators and transmission grid congestion. From the substation at the grid exit point to the household smart meters, the conditions of the large primary and secondary distribution networks may differ a lot from the transmission grid conditions. Responding to the nodal price variations by all DERs may create additional problems in the local distribution networks, such as local congestion or local voltage violations. Therefore, the operational effect of DERs on the distribution networks should be factored into the scheduling formulation.

Cost of energy unserved or delayed

Similar to the issues of using the Value of Lost Load (VoLL) to reflect the reliability costs in Chapter 5, most of the DER scheduling approaches using monetary terms fail to defend the practicality of the exact cost information. One example is to use the real-time wholesale price to approximate the energy cost as discussed. The other examples are energy cost function, utility function or price elasticity, which are terms used in economics but very hard to derive the exact value for each individual customer under every situation. Even if the customers are willing, it is not possible for them to specify the exact dollar amount, for instance, of running a dishwasher right now or 5 minutes later. Circumstances may change frequently for a rational customer who wants to get dish washing done as soon as possible in a particular situation regardless of the price. Therefore, the cost information used in the monetary formulation can be quite subjective and not always reliably applicable in practice.

Operational distributor pricing and cost reconciliation

The network components of the electricity price are based on the transmission grid and distribution network investment, which can be a fairly large portion of the electricity bill apart from the energy component. Signalling indicators that coordinate the DER schedules according to the network conditions can achieve efficient network operation. However, a proactive distributor who seeks to maximise the network asset utilisation using DER still finds it very hard to quantify the benefit of DER based on their usual practice. For example, the distribution planning is usually done in the long horizon and the distributor regulation often produces annualised distributor revenue. Attempts have been made to dissect the annualised asset investment costs by the peak hours in order to produce distributor pricing in an operational sense [41]. However, the operational cycles of some DERs can be a few hours, such as PEV charging or water heating, other DERs have much smaller operational cycles, such as PV, space heating or space cooling. Therefore, not only the time interval duration of DER scheduling needs to be considered, the ease to align with the reconciliation process is also important to satisfy the distributor regulation requirement.

6.1.2 Major contributions

The proposed DER scheduling framework addresses the triple roles to be acted by a distributor, as the distribution grid planner, operator and DER service aggregator. The framework aims to derive DER scheduling instructions with operational pricing information. Firstly, cost estimation is avoided in the proposed distributor scheduling objective formulation by using the so-called 'time value' from deferrable DER devices, because it can be quite subjective, unreliable, and sometimes impossible to specify the exact dollar amount of deferring or interrupting a DER service. Secondly, the framework enables the distributor to grasp a near real-time overview of the availability and locations of DER devices as well as their likely impact on the distribution grid over time, without having to have the full knowledge and control of every DER device. Thirdly, the framework achieves the goal of load shaping in distribution grid, which also produces marginal-like values after DER scheduling to mimic the operational spot pricing mechanism. Furthermore, the proposed DER scheduling is suited to different types of market structures, from systems without varying wholesale market prices to systems with fully deregulated market structure.

6.2 Proposed scheduling framework

6.2.1 Overview of DER scheduling framework

Communication and control architecture

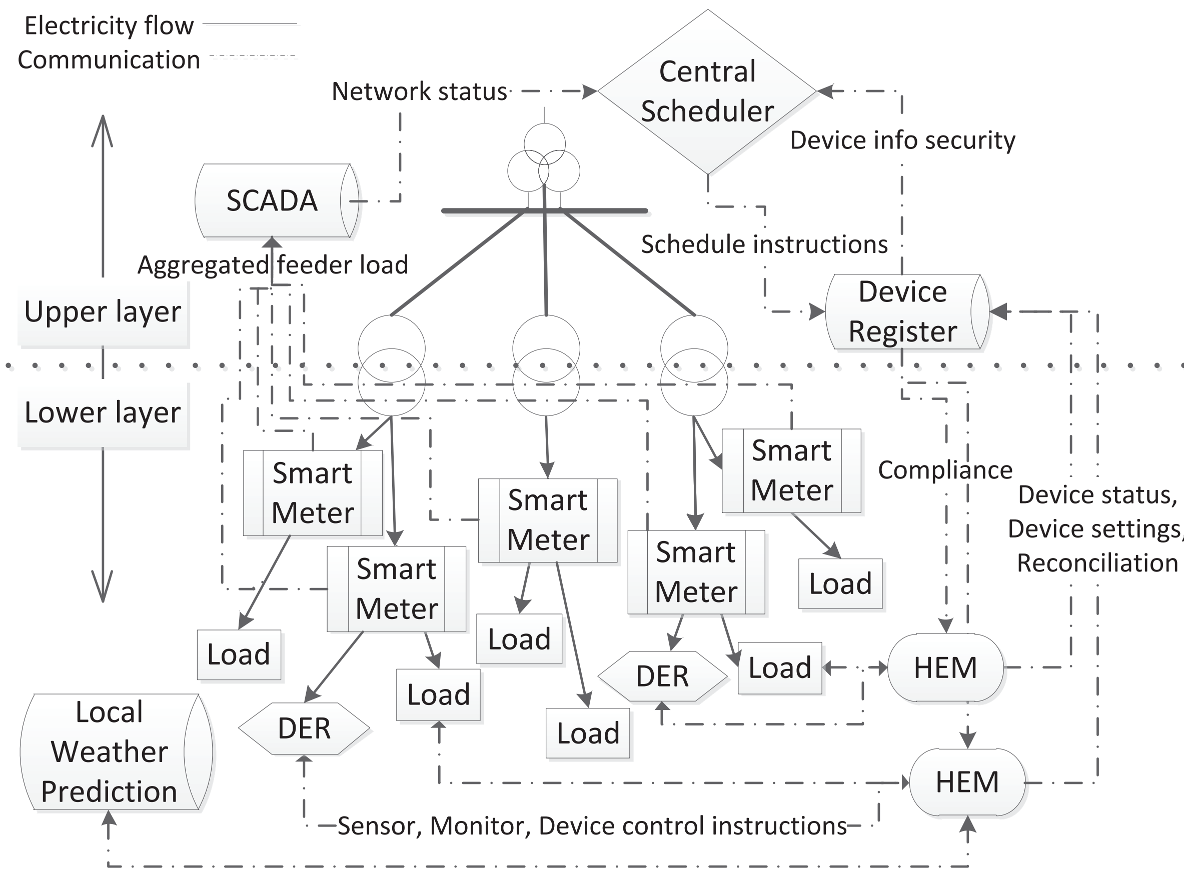

Figure 6.1: Physical connection and functions of two-layered architecture

The proposed DER scheduling framework adopts a two-layered architecture, as shown in Fig. 6.1. Electricity flows from a substation and MV system in the upper layer, to loads and DERs connected to Smart Meters in the lower layer, MV/LV distribution transformers are between the two layers. In communication infrastructure, the Device Register is a server that collects the status of DER devices across the grid and stores the instructions for each DER device from the Central Scheduler. HEMSs in the lower layer are like distributed agents in charge of updating the device status to the Device Register, and fetching DER scheduling instructions stored in the Device Register.

Centralised distributor scheduling

Distribution management system (DMS) is becoming more sophisticated than before, which can have the capability of distribution state estimation using the aggregated Smart Meter data, and the distribution grid status data from the Supervisory Control and Data Acquisition (SCADA) or distribution Phasor Measurement Unit (PMU). For loads and DERs that are controlled by other entities rather than the distributor, their aggregated usage information will be reflected only in Smart Meter readings but not in Device Register. At each time step, a scenario of the grid with the available devices in the Device Register is extracted by the Central Scheduler inside the DMS, and an optimal schedule of DER devices is produced for the scenario consecutively.

Decentralised device coordination

DER modelling and controlling details are done by HEMSs in the lower layer. HEMSs are equipped with temperature setting and sensor for TCLs, battery state-of-charge monitor for an EV or ESS, PV output prediction based on local weather, and customer waiting time input for an EV, appliances and hot-water heating. Individual HEMS keeps tracking the status of DER devices and updating the information to the Device Register whenever there is a change of device status. Once instructions are recorded in the Device Register, individual HEMS will control the specific DER device to ensure compliance.

6.2.2 Decentralised modelling of device monitoring and control

Summary of device modelling parameters

There are classification systems to capture a multitude of demand patterns in device models, such as to classify loads as uncontrollable, curtailable, interruptible, uninterruptible (but deferrable), thermal and storage as in [157]. The classification of DER devices used in this paper is summarised in Table 6.1.

Two important characteristics of DERs are extracted from their physical models for distributor scheduling and pricing purposes, which are the total device energy and deferability.

Table 6.1: DER device type numbering and characteristics

Type	Deferrable	Interruptible	Time-limited	Thermal loss	Examples
1	Yes	No	Yes	No	Dryer, dishwasher, washing machine
2	Yes	Yes	Yes	No	EV
3	Yes	Yes	Yes	Yes	Water heating
4	Yes	No	No	Yes	Space heating, Refrigerator
5	Yes	Yes	No	No	ESS
6	No	Yes	No	No	PV, wind

The total device energy has several meanings depending on DER device type. It can be calculated as the sum of demand over one or multiple time intervals required to finish one cycle of the device's normal operation. It can also refer to as the total energy output over one time interval for a PV, or the energy stored in an ESS or EV. For TCLs, the total device energy can be related to the total energy drawn for a TCL to operate it from one temperature band to the other band over multiple time intervals. Five parameters are used to quantify the energy status for all six types of DERs:

- $\bar{\Gamma}_{n,w}$ (p.u.) is the device's average demand or output in an operational state w,
- EB_n (hour·p.u.) is the starting device energy requirement to operate the device,
- TB_n (hour) is the time window over which the device can operate,
- ET_n (hour·p.u.) is the maximum energy can be stored, and
- EF_n (p.u.) is the incremental power requirement to compensate for heat loss.

The other characteristic of DERs is the ability of some DERs to temporarily shift their load or output, such as all deferrable DER devices except the PV.

Device usage deferability

For deferrable and time-constrained demand (type 1, 2 and 3), at least three parameters of EB_n, TB_n and $\bar{\Gamma}_{n,w}$ are required. The following two equations can derive the available time $TA_{t,n}$ as the deferrable device approaches its time constraint, which captures its diminishing deferability throughout all time intervals:

$$TA_{t,n} = \begin{cases} TB_n - \dfrac{EB_n}{\bar{\Gamma}_n^{\mathrm{up}}} - \tau_t, & \forall(t,n) : t = 1, DT_n \in \{1,2,3\}, \bar{\Gamma}_n^{up} > 0 \\ TA_{t-1,n} - \tau_t, & \forall(t,n) : t > 1, DT_n \in \{1,2,3\} \\ 0, & \text{otherwise} \end{cases} \tag{6.1}$$

$$TS_{t,n} = \begin{cases} TA_{t,n}, & \forall(t,n) : t = 1 \\ TA_{t,n} + TS_{t-1,n}, & \forall(t,n) : t > 1 \\ 0, & \text{otherwise} \end{cases} \tag{6.2}$$

where

- $TA_{t,n}$ is the available time as the deferrable device approaches its time constraint,
- t is time interval,
- n is DER device number,
- $\bar{\Gamma}_n^{up}$ is device's average demand in the highest loading state,
- τ_t (hour) is the actual time duration of time interval t,
- DT_n is DER device type, and
- $TS_{t,n}$ is the accumulated time available $TA_{t,n}$ over multiple time intervals that device n can be scheduled while providing system benefit.

Total device energy modelling

For TCL with heat dissipation (type 3 and 4), $\bar{\Gamma}_{n,w}$, EB_n, ET_n and EF_n are approximated using a linear model as in [158], but they can be dynamically updated by the HEMS to account for any unusual situation, such as when a house door is left open thus heat dissipation is greater than normal. Once the target temperature T_n^{o} is set, the actual temperature is allowed to fluctuate between a band of $2 \cdot T_n^{\mathrm{b}}$. where

- T_n^{o} is the target temperature, and
- T_n^{b} is the temperature band.

For heating, when a heater is left to run a full normal cycle without any control, and the time t_n^{off} it takes for the temperature to drop from $T_n^{\mathrm{o}} + T_n^{\mathrm{b}}$ to $T_n^{\mathrm{o}} - T_n^{\mathrm{b}}$ can be recorded. Once the heater turns on again, the total electricity demand ET_n to raise the temperature from $T_n^{\mathrm{o}} - T_n^{\mathrm{b}}$ to $T_n^{\mathrm{o}} + T_n^{\mathrm{b}}$

and the time t_n^{on} are both recorded. The average demand $\bar{\Gamma}_{n,w}$ is updated by the HEMS:

$$\bar{\Gamma}_{n,2} = \frac{ET_n}{t_n^{\text{on}}}, \quad \forall n : DT_n \in \{3,4\} \tag{6.3}$$

$$EF_n = \frac{ET_n}{t_n^{\text{off}} + t_n^{\text{on}}}, \quad \forall n : DT_n \in \{3,4\} \tag{6.4}$$

where

- t_n^{on} is the time it takes for the temperature to raise from $T_n^{\text{o}} - T_n^{\text{b}}$ to $T_n^{\text{o}} + T_n^{\text{b}}$ in heating mode,
- t_n^{off} is the time it takes for the temperature to drop from $T_n^{\text{o}} + T_n^{\text{b}}$ to $T_n^{\text{o}} - T_n^{\text{b}}$ in heating mode,
- $\bar{\Gamma}_{n,w}$ is average demand,
- $\bar{\Gamma}_{n,2}$ is the rated power of device running in state w of 2, and
- EF_n is the incremental power required to compensate for heat loss during the entire cycle, which is also updated by the HEMS.

Equations (6.3) and (6.4) still apply to cooling, except

- T_n^{on} is the time it takes to lower the temperature from $T_n^{\text{o}} + T_n^{\text{b}}$ to $T_n^{\text{o}} - T_n^{\text{b}}$ in cooling mode.

Specifically for water heaters (type 3), TB_n from customer input is also necessary to indicate the next time period in which hot water will most likely be used. The process to determine EF_n and ET_n is the same as above during a cycle without any hot-water usage. However, EB_n needs to be updated by the HEMS whenever hot water is consumed and can be approximated linearly according to the measured water temperature.

For an EV or ESS that is a storage-type device (type 2 and 5), EB_n is the battery's initial state-of-charge, and ET_n is battery capacity. Energy dissipation factor EF_n is not used, but operating time window TB_n is required from customer input to indicate the desired time for EV charging to finish. According to [159], battery power can be estimated and its state-of-charge can be linearly modelled. It is worth noting that in the proposed model,

- $EB_n = 0$ means the battery is fully charged,
- $EB_n = ET_n$ means fully discharged, and
- Any value in between means EVs are partially charged.

Multi-state device operations

The device's average demand in the highest possible state $\bar{\Gamma}_n^{\text{up}}$ (p.u.) is determined by:

$$\bar{\Gamma}_n^{\text{up}} = \begin{cases} \bar{\Gamma}_{n,2}, & \forall n : DT_n \in \{1,3,4,5\} \\ \bar{\Gamma}_{n,3}, & \forall n : DT_n = 2, \dfrac{EB_n}{\bar{\Gamma}_{n,2}} > TB_n \\ \bar{\Gamma}_{n,2}, & \forall n : DT_n = 2, \dfrac{EB_n}{\bar{\Gamma}_{n,2}} \leq TB_n \\ \bar{\Gamma}_{n,1}, & \forall n : DT_n = 6 \end{cases} \tag{6.5}$$

EV fast charging is an exception that the fast charging mode, as shown in [28], is not enabled unless TB_n is too short for the slow charging mode to fulfill EB_n.

Lastly, the lowest possible state of device's average demand or output $\bar{\Gamma}_n^{\text{lo}}$ (p.u.) is:

$$\bar{\Gamma}_n^{\text{lo}} = \begin{cases} 0, & \forall n : DT_n \in \{1,2,3,4\} \\ \bar{\Gamma}_{n,1}, & \forall n : DT_n \in \{5,6\} \end{cases} \tag{6.6}$$

where

- $\bar{\Gamma}_n^{\text{up}}$ is the device's average demand in the highest possible state,
- $\bar{\Gamma}_n^{\text{lo}}$ is the lowest possible state of device's average demand or output, and
- The values of $\bar{\Gamma}_{n,w}$ obey the rule of $\bar{\Gamma}_{n,3} > \bar{\Gamma}_{n,2} > 0 > \bar{\Gamma}_{n,1}$.

Only an ESS or PV can have negative output in the supply state, and EV charging is assumed uni-directional.

6.2.3 Centralised distributor scheduling formulation

Objective function

The objective function is formulated as:

$$\max \;\; OBJ = \sum_{t,n} TS_{t,n} \cdot \Gamma_{t,n} \cdot \tau_t \tag{6.7}$$

where

- $\Gamma_{t,n}$ (p.u.) is the variable whose result shows the optimal schedule of registered DERs,

- τ_t (hour) is the actual time duration of time interval t, and
- $TS_{t,n}$ is the accumulated time that the flexible device has been providing its benefit since registered, which represents the 'time value' of a deferrable device.

The objective is to maximise deferrable devices that are available to be scheduled by a distributor, as these flexible resources should be kept in the system in a coordinated fashion and their benefits should be realised only if needed by releasing them as normal loads.

The actual time duration of each time interval τ_t can either be fixed or varying. Normally duty-cycle based control ($DT_n = 4$) or PV generation ($DT_n = 6$) requires scheduling with higher time resolution, but some other types of DERs ($DT_n \in \{1, 2, 3, 5\}$) require a longer scheduling horizon. The limited computation resource means that a trade-off must be made, otherwise the total number of time intervals will be too large to practically get a solution for real-time operation. By varying τ_t, a smaller value is used for intervals closer to the present time ($t = 0$) and gradually increasing τ_t for intervals further into the future with less certainty. To ensure optimal, τ_t is the same for all DER devices in a particular time interval t.

Constraints formulation

The objective function is subject to constraints (6.8) to (6.13):

$$\frac{U_{t,m} - U_{t,m'}}{KF_{m,m'}} = \sum_{m'' \in \Omega_{m',m''}} \left(\Gamma'_{t,m''} + \sum_{n \in \Psi_{n,m''}} \Gamma_{t,n} \right), \qquad \forall (t, m, m') : \Theta_{m,m'} = 1, Rg_{m,m'} = 0 \tag{6.8}$$

where

- $U_{t,m}$ is the sending-end voltage of a branch,
- $U_{t,m'}$ is the receiving-end voltage of a branch,
- m is the sending-end node,
- m' is the receiving-end node,
- m'' is a downstream node to the receiving end m',
- $KF_{m,m'}$ is voltage change factor,
- $\Gamma'_{t,m''}$ is the load (p.u.) measured by smart meter including controlled DER loads in operation and the loads responded to real-time energy prices if available,

- $\Gamma_{t,n}$ is the DER load indicated by the HEMS but held in standby mode to be scheduled,
- $\Theta_{m,m'}$ is an upper triangular matrix if two nodes are connected by a branch,
- $Rg_{m,m'}$ is an upper triangular matrix represents a voltage regulator,
- $\Omega_{m',m''}$ is an upper triangular matrix represents the connectivity of any downstream node to the receiving end m', and
- $\Psi_{n,m''}$ is the connectivity of a DER load to the node.

Firstly, the link is established for branch voltage $U_{t,m}$ and $U_{t,m'}$ (p.u.) between nodes m and m', which the net value of all loads and DERs downstream to node m' on the right-hand side can cause the receiving-end voltage $U_{t,m'}$ to drop or rise from the sending-end voltage $U_{t,m}$ on the left-hand side, according to voltage change factor $KF_{m,m'}$ (p.u./p.u.) of the branch.

The voltage link is valid for two nodes connected by a branch as denoted by an upper triangular matrix $\Theta_{m,m'}$, excluding branches that represent regulators by another upper triangular matrix $Rg_{m,m'}$. The linear approximation of voltage change has included the effect of reactive power and branch reactance on voltage. m'' represents any of the downstream nodes to the receiving end m' of a given branch as denoted by the upper triangular matrix $\Omega_{m',m''}$. $\Gamma'_{t,m''}$ is the load (p.u.) measured by smart meter including controlled DER loads in operation and the loads responded to real-time energy prices if available. $\Gamma_{t,n}$ is the DER load indicated by the HEMS but held in standby mode to be scheduled, which is connected to node m'' as denoted by $\Psi_{n,m''}$. The summation sign inside the bracket sums up all standby DER loads connected to node m''. The summation sign outside the bracket sums up all downstream loads to node m'.

Meanwhile, all nodal voltages must be bounded:

$$LV^{\mathrm{lo}} \leq U_{t,m} \leq LV^{\mathrm{up}} \qquad \forall t, \forall m \tag{6.9}$$

where

- LV^{lo} is the lower voltage limit (p.u.), and
- LV^{up} is the upper voltage limit (p.u.).

Voltages normally have the allowed band ($LV^{\mathrm{up}} - LV^{\mathrm{lo}}$) from 12% to 20% (or ±6% to ±10%). Typically in New Zealand LV^{lo} is 0.94 p.u, but considering voltage drop along the service cables inside buildings, 0.98 p.u. with a slight voltage drop headroom of 0.04 p.u. can be used to account for any approximation error or uncertainty in the system.

Apart from voltage limits, the other consideration is the thermal limit $LI_{m,m'}$ (p.u.) related to bidirectional currents:

$$-LI_{m,m'} \leq \frac{U_{t,m} - U_{t,m'}}{Z_{m,m'}} \leq LI_{m,m'}, \quad \forall(m,m') : m' > m, \Theta_{m,m'} = 1 \tag{6.10}$$

where

- $LI_{m,m'}$ is the bidirectional current thermal limit (p.u.),
- $Z_{m,m'}$ is linearly approximated branch impedance (p.u.),
- $U_{t,m}$ is the sending-end voltage of a branch,
- $U_{t,m'}$ is the receiving-end voltage of a branch,
- m is the sending-end node, and
- m' is the receiving-end node.

The branch current depends on the voltage difference between the sending end m and receiving end m', and the linearly approximated branch impedance $Z_{m,m'}$ (p.u.) either by using distribution state estimation or by calculating the branch current and the voltage differential in successive runs of distribution load-flow near the real-time grid operating point.

The individual DER has the upper bound $\bar{\Gamma}_n^{\mathrm{up}}$ and lower bound $\bar{\Gamma}_n^{\mathrm{lo}}$ on its average demand or output:

$$\begin{cases} \Gamma_{t,n} = \bar{\Gamma}_n^{\mathrm{lo}} \cdot PV_t, & \forall(t,n) : DT_n = 6 \\ \bar{\Gamma}_n^{\mathrm{lo}} \leq \Gamma_{t,n} \leq \bar{\Gamma}_n^{\mathrm{up}}, & \text{otherwise} \end{cases} \tag{6.11}$$

where

- PV_t is a weather dependent PV variation factor,
- $\bar{\Gamma}_n^{\mathrm{up}}$ is the device's average demand in the highest possible state,
- $\bar{\Gamma}_n^{\mathrm{lo}}$ is the lowest possible state of device's average demand or output, and
- $\Gamma_{t,n}$ (p.u.) is the variable whose result shows the optimal schedule of registered DERs.

The maximum PV generation output is modified by the weather dependent PV variation factor PV_t between 0 and 1 with 1 being full output, which can be predicted using the local cloud coverage and wind speed.

$E_{t,n}$ (hour·p.u.) tracks the status of device energy at the beginning of each interval, which is also the state-of-charge specifically for an ESS or EV. $E_{t,n}$ is initialised to the starting energy

EB_n required to finish a device's job cycle. Once $E_{t,n}$ is depleted to 0, device operation is finished. Finally, the device energy status is also constrained by its maximum energy capacity ET_n.

$$\begin{cases} E_{t,n} = EB_n, & \forall (t,n) : t = 1, DT_n \neq 6 \\ E_{t,n} = E_{t-1,n} - \Gamma_{t,n} \cdot \tau_t, & \forall (t,n) : t \neq 1, DT_n \in \{1,2,5\} \\ E_{t,n} = E_{t-1,n} - (\Gamma_{t,n} - EF_n) \cdot \tau_t, & \forall (t,n) : t \neq 1, DT_n \in \{3,4\} \\ 0, & \text{otherwise} \end{cases} \tag{6.12}$$

$$0 < E_{t,n} \leq ET_n, \quad \forall (t,n) : DT_n \neq 6 \tag{6.13}$$

where

- EF_n is the incremental energy to compensate for heat dissipation of a TCL,
- τ_t is the actual time duration,
- $E_{t,n}$ is the status of device energy (hour·p.u.),
- EB_n is the starting energy required to finish a device's job cycle, and
- ET_n is the maximum energy capacity.

6.3 Implementations of centralised scheduling

6.3.1 Test on the IEEE 4-bus distribution system

Grid and device parameters

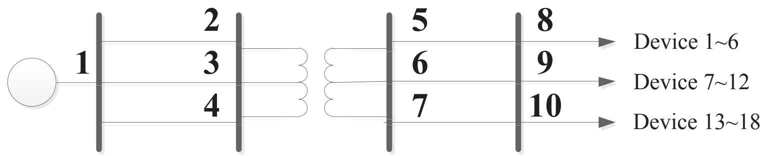

Figure 6.2: The IEEE 4-bus test distribution system with 18 aggregated DER devices

To consider the unbalanced 3-phase operation, the IEEE 4-bus distribution system, as shown in Fig. 6.2, is marked with 10 nodes. Each single-phase load is assumed to have six types of different devices aggregated, so there are a total of 18 devices. The single-phase voltage bases are 7.2kV and 2.4kV on the two sides of the transformer. As an example, the lower limit of grid voltages LV^{lo} is set to 0.9 per unit (p.u.), and the upper limit LV^{up} is set to 1 p.u.. The total number of time intervals T is set to 12, with each interval representing 0.5 hour of actual time duration τ_t.

Load-flow is run using GridLAB-D with the wye-wye transformer connection. The balanced peak loads of 1800kW in each phase are reduced to half (0.45p.u. with 2000kVA base). As shown in Table 6.2, branch impedance $Z_{m,m'}$ is linearly approximated, which is the quotient of nodal voltage difference and branch current in per unit.

Voltage change factor $KF_{m,m'}$ of a branch is the quotient of nodal voltage difference and the sum of all downstream loads in per unit, which can be dynamically updated depending on the grid loading conditions. When a branch has a voltage rise, voltage change factor is calculated as negative. Values of the downstream-node matrix $\Omega_{m,m'}$ can be visually determined from Fig. 6.2, which are true for the following pairs of nodes: 1-2, 1-3, 1-4, 1-5, 1-6, 1-7, 1-8, 1-9, 1-10, 2-5, 2-8, 3-6, 3-9, 4-7, 4-10, 5-8, 6-9, 7-10, 8-8, 9-9, and 10-10.

Table 6.2: Voltage change factor & approximated branch impedance for the IEEE 4-bus system with 0.45p.u. loading

m	Voltage	m'	Voltage	Current	$KF_{m,m'}$	$Z_{m,m'}$
1	1.0000	2	0.9947	0.5458	0.0118	0.0097
1	1.0000	3	0.9962	0.5348	0.0084	0.0071
1	1.0000	4	0.9955	0.5399	0.0101	0.0084
2	0.9947	5	0.9742	0.5458	0.0456	0.0376
3	0.9962	6	0.9761	0.5348	0.0447	0.0376
4	0.9955	7	0.9750	0.5399	0.0454	0.0379
5	0.9742	8	0.9160	0.5458	0.1292	0.1065
6	0.9761	9	0.9350	0.5348	0.0913	0.0768
7	0.9750	10	0.9261	0.5399	0.1086	0.0905

Parameters of different DER devices in simulation are in Table 6.3 and Table 6.4. The metered normal load $\Gamma'_{t,m}$ of 0.45p.u. is kept constant during all time intervals and PV output is set to 100% with no variation, to clearly see the effect of scheduling on shaping the load profile.

Table 6.3: Parameters used for different types of DER devices

n	DT_n	$\bar{\Gamma}_{n,1}$	$\bar{\Gamma}_{n,2}$	$\bar{\Gamma}_{n,3}$	EB_n	ET_n	EF_n
1, 7, 13	2	n/a	0.05	0.2	0.75	1	n/a
2, 8, 14	5	-0.3	0.3	n/a	0.2	0.5	n/a
3, 9, 15	1	n/a	0.1	n/a	0.2	0.2	n/a
4, 10, 16	4	n/a	0.05	n/a	0.01	0.05	0.02
5, 11, 17	3	n/a	0.2	n/a	0.15	0.3	0.01
6, 12, 18	6	-0.1	n/a	n/a	n/a	n/a	n/a

Table 6.4: DER device settings of operational time window

DT_n	2			1			3		
n	1	7	13	3	9	15	5	11	17
TB_n	8	7	6	6	5	4	4	3	2

Device scheduling results

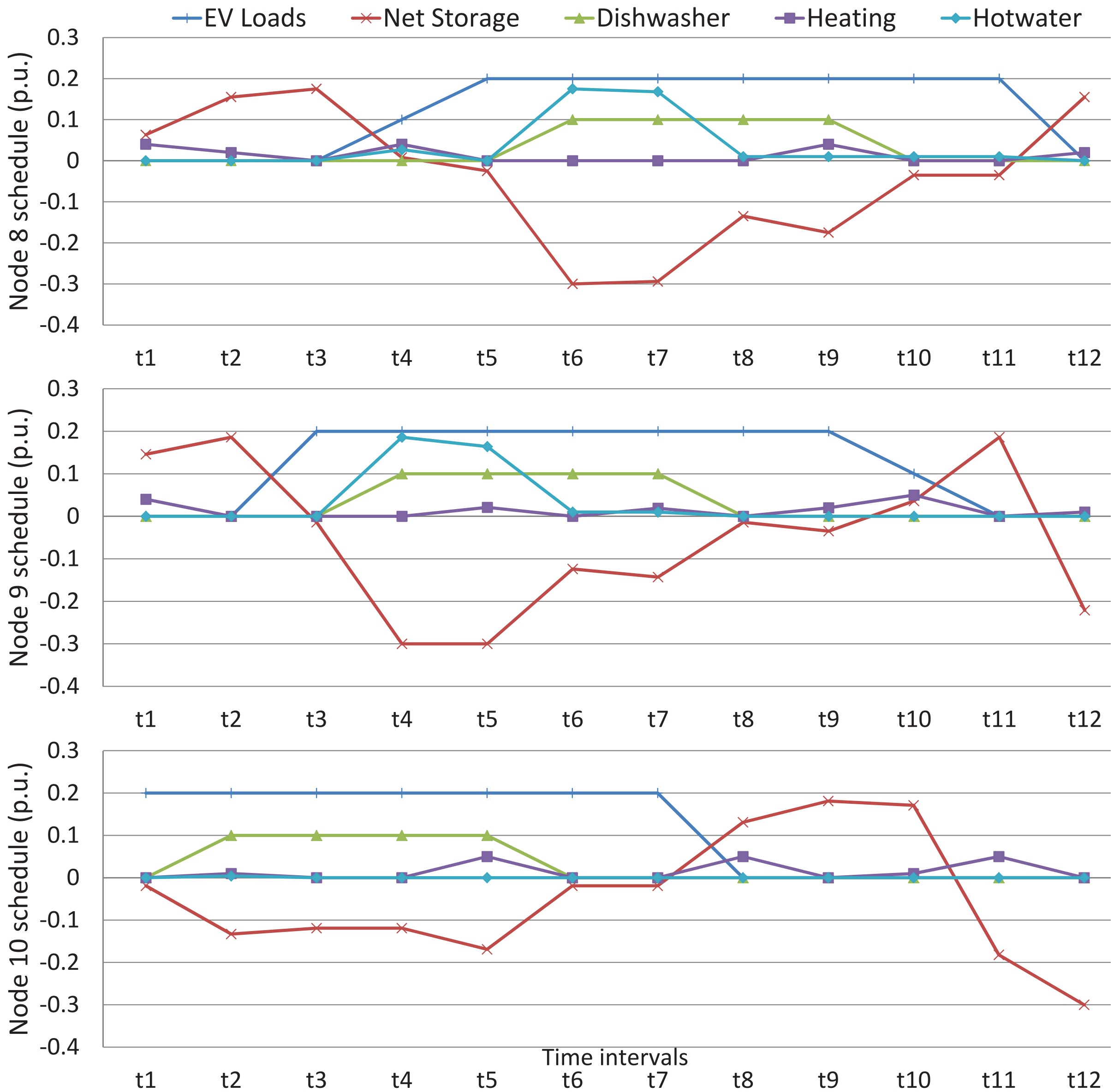

Figure 6.3: Scheduling results at nodes 8, 9, and 10 in the IEEE 4-bus distribution test system

Device scheduling results at nodes 8, 9, and 10 are shown in Fig. 6.3. Because ESS can be scheduled to charge or discharge, in a particular time interval, the net storage is defined as the output difference between the total charging demand of storage devices and the total discharging output of storage devices. For example, in $t = 12$ at node 8, the net storage is positive, so there are more storage devices charging than discharging at that time. Three storage loads are scheduled to charge when the distribution grid only needs to serve three normal loads of 0.45 p.u., but are scheduled to discharge during the time intervals when most of the extra EV and dishwasher loads start to operate. Three EV loads and three dishwasher loads are all scheduled to finish just before the depletion of their time available $TA_{t,n}$, which are initialised as in Table 6.4. While the other two hot-water loads are scheduled normally, the hot-water load at node 10 is scheduled to not operate at the this particular instance of scheduling. This is because the EV and dishwasher loads at node 10 are both on a tight schedule with small values of TB_n. The storage's starting 25% state-of-charge is not enough either to support all three devices at the same time. However, the device availability and network conditions are dynamically changing as time goes on, so in the later instances of scheduling, the hot-water load at node 10 may still have the chance to be scheduled to operate.

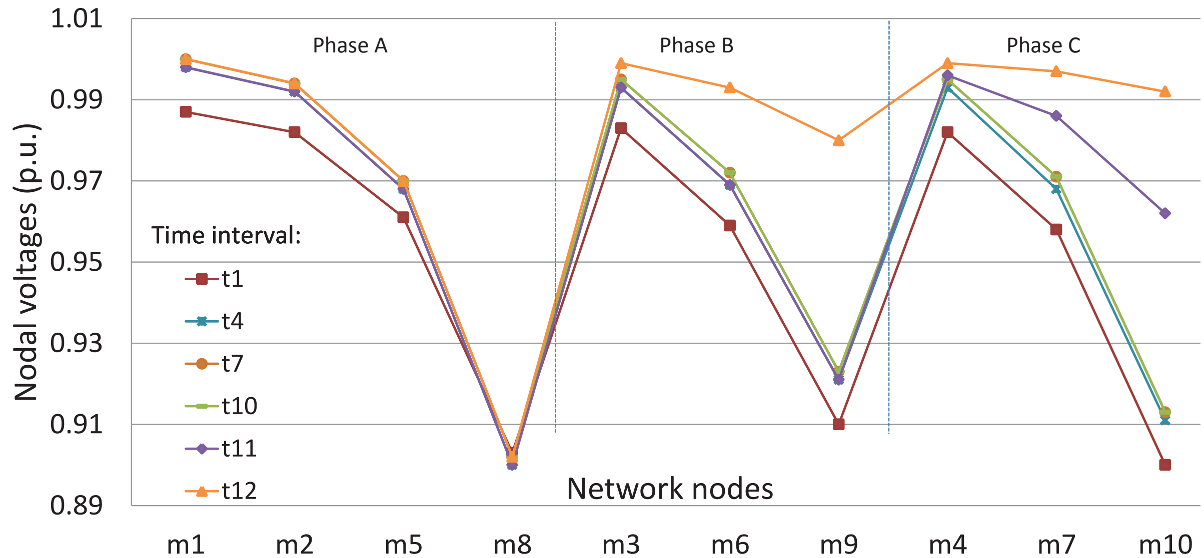

Figure 6.4: The IEEE 4-bus test distribution system nodal voltages in the selected time intervals

Distribution grid nodal voltages are plotted in Fig. 6.4 for the selected time intervals, which mostly have similar pattern during the time intervals between the starting and ending intervals. Observing voltages in the last two time intervals of $t = 11$ and $t = 12$, at nodes 6 and 9 of phase B, and nodes 7 and 10 of phase C, it can be seen that the corresponding two phases are quite loosely loaded near the end of scheduling horizon. This is because most of the time-constrained devices in these two phases are scheduled to operate in the earlier time intervals and storage devices are also close to being fully charged near the ending intervals. Overall, the scheduling algorithm tries to maximise the utilisation of distribution grid loading capacity and ensure the flexibility of all available DERs.

Distributor pricing based on the 'time value'

After obtaining the optimal schedule, marginal values of (6.12) are shown in Table 6.5. The marginal values have an interesting aspect, which reflect the additional distribution grid flexibility that can be obtained by shifting the time-constrained demand to another interval, if the operation of that DER device can still be shifted. Comparing three devices of the same type, the devices connected to node 8 all have the highest marginal values and the ones connected to node 10 the least. This is because the devices at node 8 have been staying in the system for a longer time period, thus providing more flexibility for other devices to be scheduled. Potentially these 'shadow prices' resemble the locational marginal prices in the transmission grid economic dispatch, but they are expressed in terms of the 'time value' instead of the typically used monetary terms.

Table 6.5: Marginal values of equation (6.12) in the optimal schedule

DT_n	2			1			3		
n	1	7	13	3	9	15	5	11	17
Marginal	24	10	0	25	12	1	16	7.5	0

Actual contribution of the individual DER device can be quantified depending on the accumulation of marginal values from all scheduling scenarios over a period of time. Assuming that \$100 of investment cost saving incentives need to be distributed to DER owners in the 4-bus test distribution system, three ESS owners may equally receive one third of \$50, because controlled ESS charging or discharging can provide system benefit at all time. The sum of all marginal values in Table 6.5 is 95.5, so the listed devices may receive a portion of the other half \$50 (e.g., $\frac{24}{95.5}$ for device $n = 1$).

6.3.2 Test on the IEEE 8500-node distribution system

Grid and device parameters

To demonstrate the practicality on a realistically large distribution system with a large amount of DER devices, the proposed formulation is also implemented on the IEEE 8500-node distribution network [160], as shown in Figure 6.5.

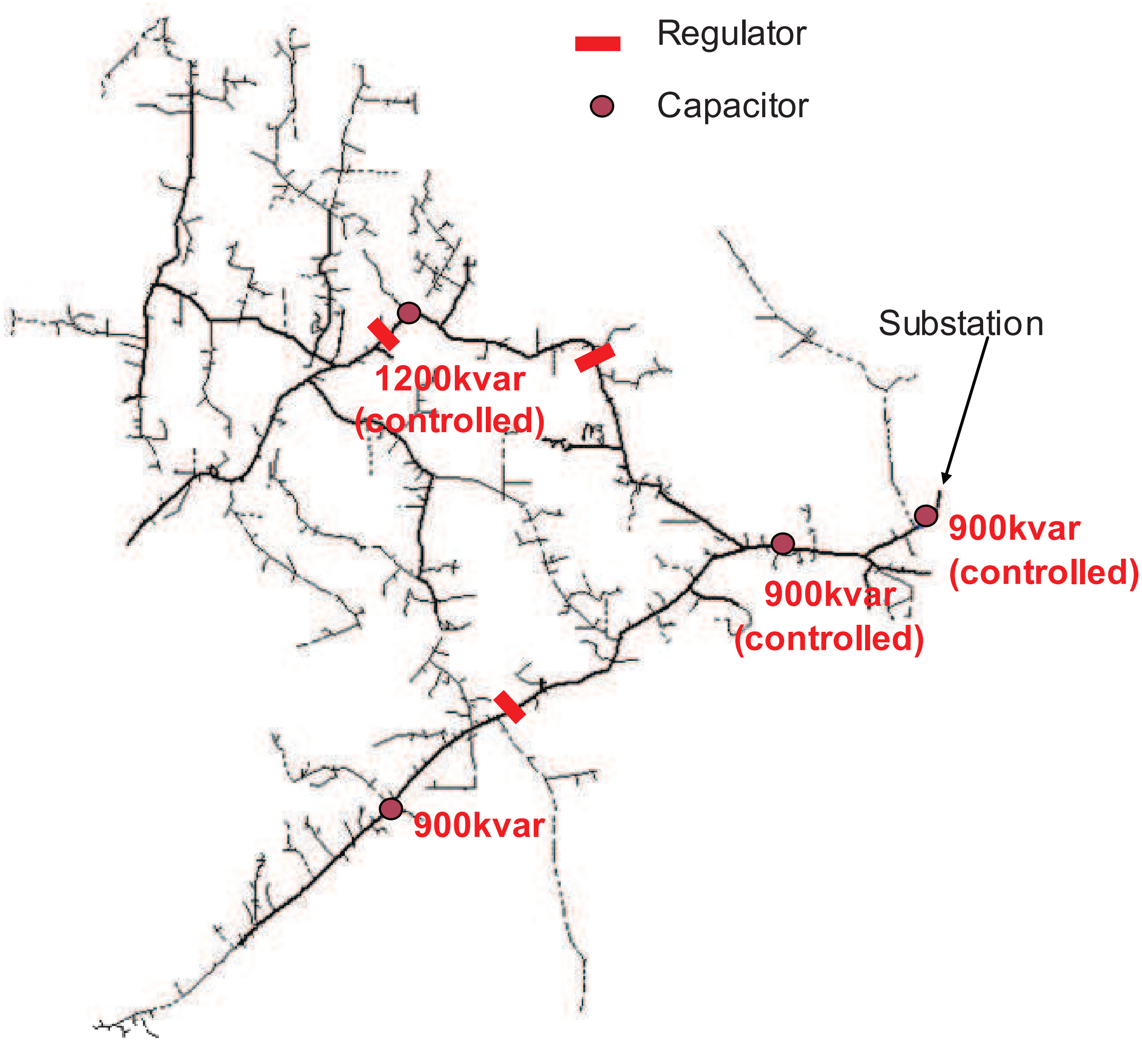

Figure 6.5: The IEEE 8500-node distribution test network

All 18832 devices are assumed to be evenly scattered across all load locations with parameters being generated according to the probability of normal distribution. Table 6.6 shows the mean values used to generate six types of DERs. Peak loads, current ratings, branch resistance and regulators information are extracted from the software OpenDSS. The voltage bases are set to 115kV, 12.47kV and 0.208kV at the substation, primary and secondary system respectively. 1000kVA is chosen as the kVA base.

Table 6.6: Mean values to randomly generate parameters for DERs

DT_n	$\bar{\Gamma}_{n,1}$, $\bar{\Gamma}_{n,2}$, $\bar{\Gamma}_{n,3}$	EB_n	ET_n	EF_n	TB_n
1	n/a, 0.0016, n/a	0.0032	0.0032	n/a	12
2	n/a, 0.0053, 0.016	0.0106	0.0212	n/a	8
3	n/a, 0.0032, n/a	0.0016	0.0032	0.000064	4
4	n/a, 0.0025, n/a	0.000625	0.00125	0.000625	n/a
5	-0.003, 0.003, n/a	0.0045	0.009	n/a	n/a
6	-0.003, n/a, n/a	n/a	n/a	n/a	n/a

To produce intervals with varying time duration in the implementation, the first ten intervals start with a small time duration, usually 0.1 hour or 0.2 hour. The second ten intervals then increase the actual time duration by 5 times, and the third ten by 5 times again, and so on until the total scheduling horizon is reached. General Algebraic Modelling System (GAMS) is used to solve the optimisation problem. MATLAB runs the GAMS optimisation through the GDXMRW interface, and reads the results of optimisation variables and equation marginal values from GAMS.

Device scheduling results

As discussed in Section 6.2.3, to produce time intervals with varying duration in the implementation, the first ten intervals start with a small time duration, usually 0.1 hour or 0.2 hour. The second ten intervals then increase the actual time duration by 5 times, and the third ten by 5 times again, and so on until the total scheduling horizon is reached.

The scheduled DER demands or output $\Gamma_{t,n}$ are summed up for the same type of devices, as shown in Fig. 6.6, in which the 20^{th} interval is roughly a time span of 6 hours. It can be seen that storage devices are charging during a few of the intervals after $t = 0$ as positive loads to prepare for discharging in the following intervals. After most of DER loads are served, the storage schedule then follows PV output variations in the second half of scheduling horizon.

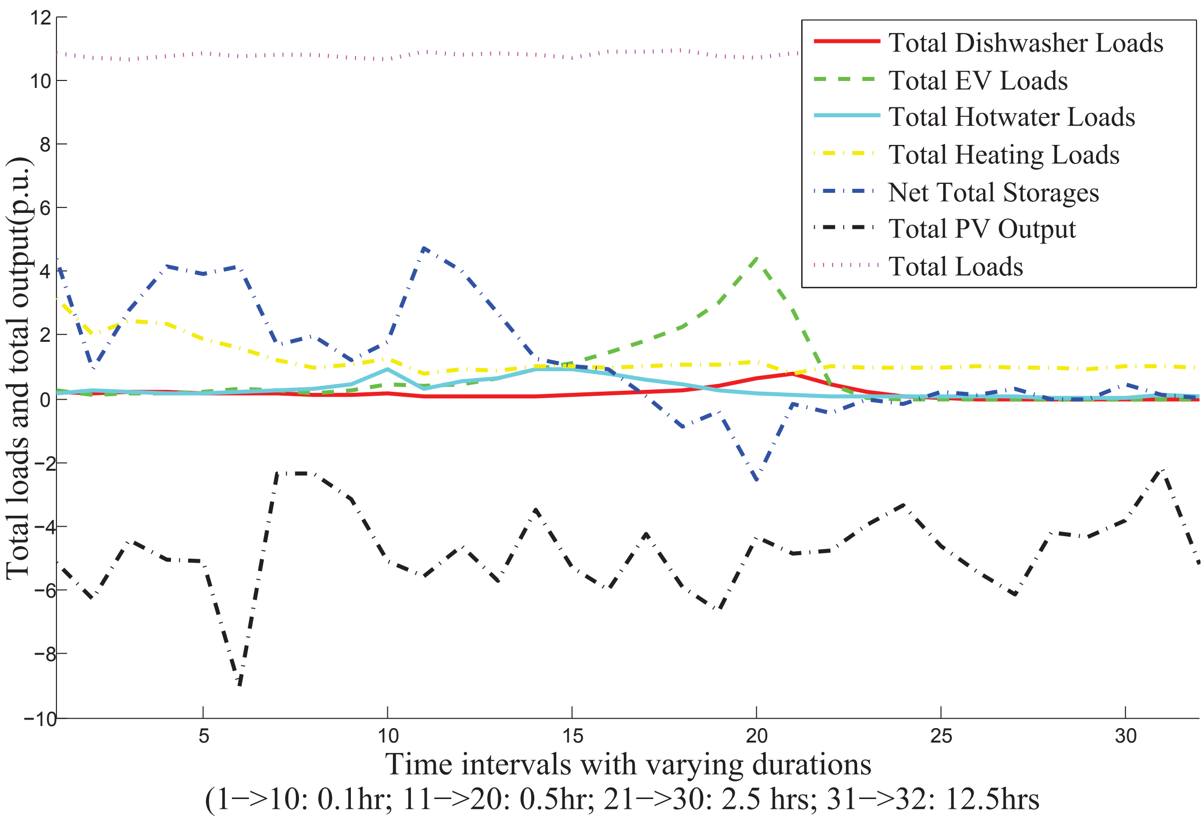

Figure 6.6: Aggregated DER schedule with varying time duration of intervals

Looking at an individual dishwasher, EV and hot-water schedule in Fig. 6.7, all are scheduled to run according to their available time respectively when $TA_{t,n} = 0$, so that customer comfort level is not affected.

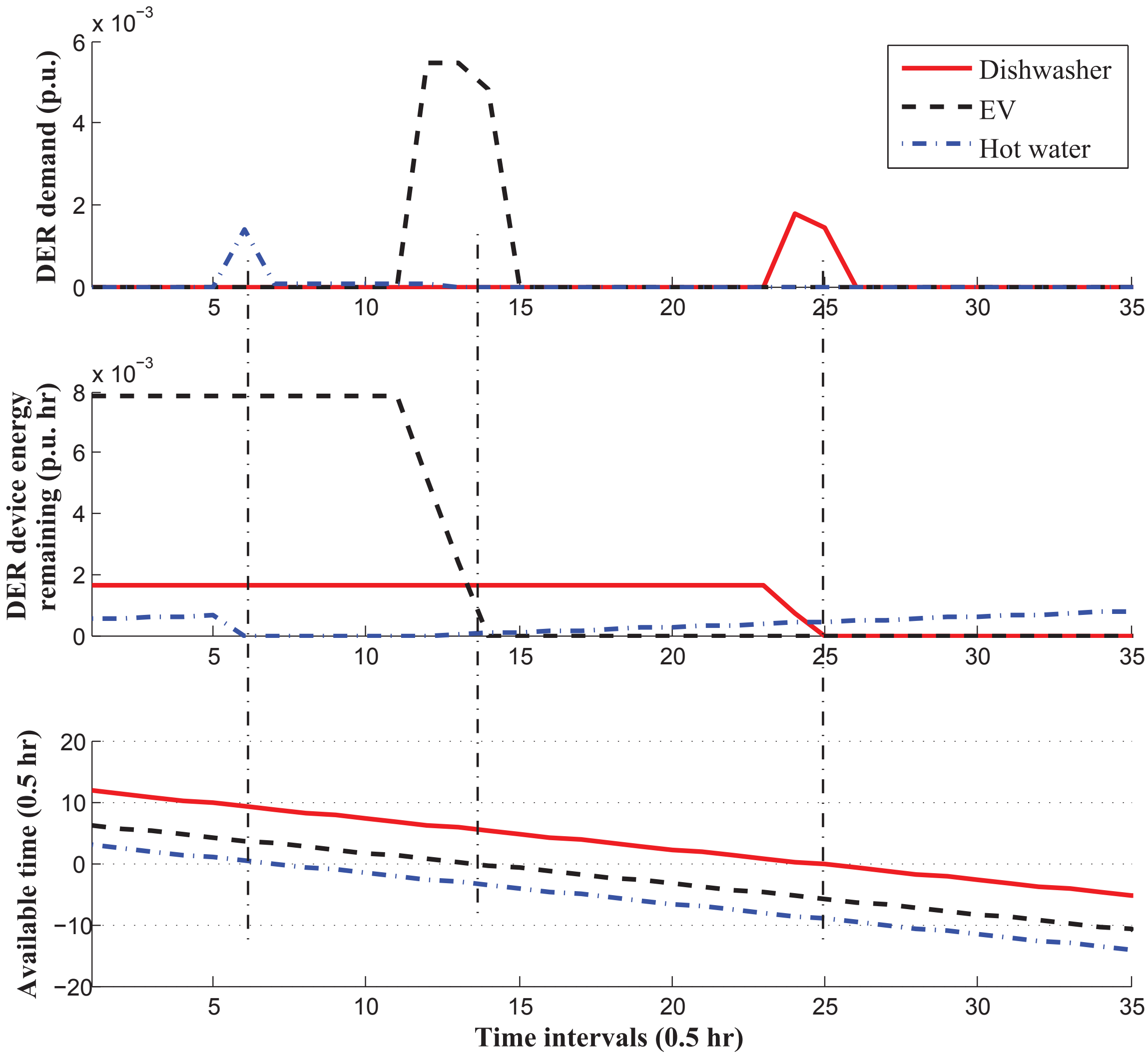

Figure 6.7: Schedule of individual DER device with respect to time available

Scheduling result is more detailed, as shown in Fig. 6.8, which captures the switching on or off of a heating load with higher time resolution. Two EV charging loads are scheduled, one is more urgent than the other. At the same time, storage scheduling is more granular, taking into account of PV output variations, as shown in Fig. 6.6. The storage devices are also scheduled to discharge when dishwasher loads and hot-water loads are scheduled to operate.

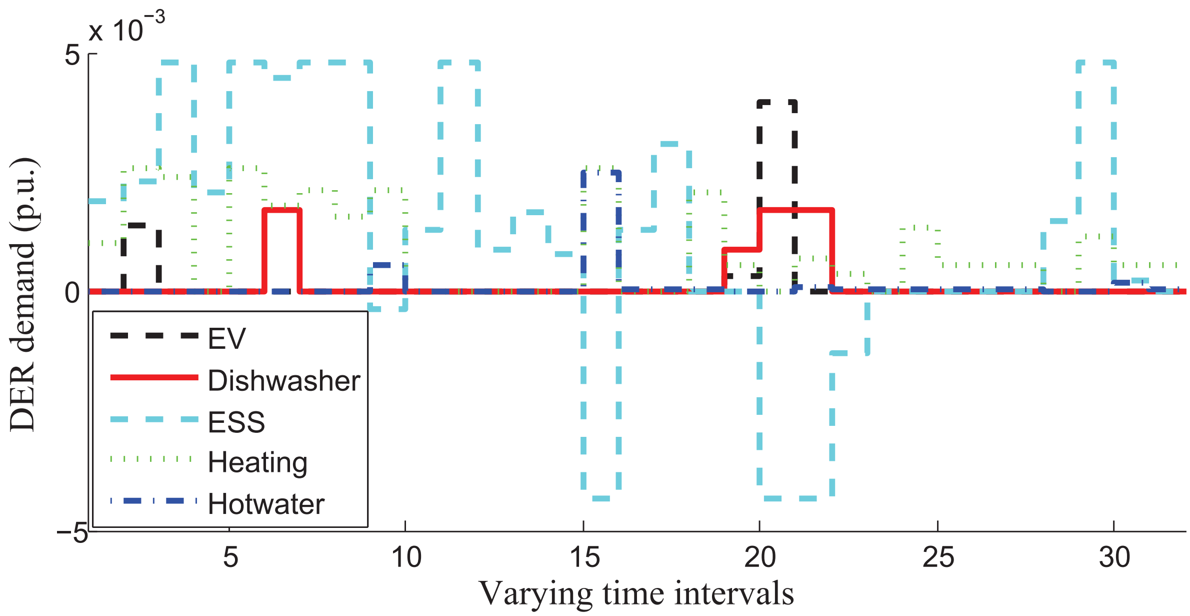

Figure 6.8: Schedule of individual device with varying time duration of intervals

Software performance

Using a personal computer with i7-4700 3.4GHz CPU and 16GB RAM, the major computation time used in the processes is listed in Table 6.7. The fixed interval scheduling is generally calculated faster than the varying interval duration scheduling, despite the number of intervals being less in the varying interval duration scheduling. For both types of scheduling, the GAMS run time is proportional to the number of DER devices if the number of intervals is similar. However, increasing the time resolution in the varying interval duration scheduling also sees a rise of computation time, unless the number of devices can be reduced. Hence, to manage the computation efficiency without losing the time resolution if the DER penetration increases, the entire network can be sectionalised to include a certain amount of DER devices in a substation zone or a zone of several distribution transformers.

Table 6.7: Computation time of different scenarios

Number of devices	18832	9416	18832	18832	9416
Number of intervals	48	48	18	28	32
Time resolution (hr)	fix 1	fix 1	0.5	0.2	0.1
GAMS run time (s)	165	88	170	521	258
MATLAB to GDX time (s)	95	76	95	95	76

6.4 Summary

The chapter has demonstrated that different types of DERs can be integrated into the SG environment based on their availability. PV outputs renewable energy but is variable in nature, so it could be mostly considered as unavailable during feeder peak loading. The consumption deferrable capability of ESS, EV charging, water heating and other deferrable DERs, therefore becomes the important resources to complement PV. The operations of some DERs are closely related to customer satisfaction, such as EV charging, water heating and non-interruptible DERs once started running, so their availabilities are scheduled to provide the maximum operational benefit to the network.

The proposed DER scheduling and pricing framework for a distributor differs from the existing ones that it uses the 'time value' of a deferrable device in the objective formulation, which avoids the impractical estimation of the cost for delaying or interrupting a service. The 'time value' represents the accumulated time that a deferrable device has been staying in the system to provide operational support without sacrificing customer comfort level. With the detailed device modelling being decentralised, distributor can gain some visibility into the low-voltage grid operation by fetching the processed device status data from a central server. The implementations on the IEEE 4-bus and 8500-node test distribution systems show an effective load shaping strategy from the central scheduling. The 'time value' based marginals derived from the optimal schedule mimic the spot pricing mechanism, which can be reconciled to the annualised investment cost savings for distributor pricing with DER devices.

The DSI approach using DER availability as outlined in the chapter matches the distributor's objective to fully utilise their distribution assets. It also facilitates the distributor revenue allocation and reconciliation depending on the actual DER contribution. Customers only need to input the time they want their DER operations to finish similar to many present-day appliances, without having to understand the mechanism or set the DER responding prices.

Future work can expand the reconciliation process in detail, with more comprehensive simulation data spanning a longer period of time. The benefit of each individual DER can be accumulated and the overall investment cost can be proportionally adjusted to derive the network tariff rebates according to the actual contribution of DERs in operation.

Chapter 7

Conclusions

7.1 Concluding remark

This thesis explored the emerging field of demand-side resources developed in the smart grid (SG) environment, factoring the de-regulated electricity market structure. Literature has been reviewed in the areas of distributed energy resources (DER) modelling and optimisation, the optimal distribution network operation and associated cost allocation methodologies, and the evolving distribution regulatory framework and business environment. The objective of the thesis was using power system network parameters and conventional indices to develop distribution pricing models that fit better into the regulatory framework.

It has been discussed in the transitional Chapter 3 that stakeholders in the de-regulated electricity market have a mutual interest in demand-side integration (DSI), with the distributor playing an important role. The methodology of the thesis was to implement the optimal network operation formulation in the standardised distribution test networks and to solve the formulation using optimisation software GAMS. Network parameters calculated by the open source distribution analysis software GridLAB-D or OpenDSS were retrieved by MATLAB or VBA to feed into the optimisation.

Two industry projects have been done to complete the implementation loop: one was to simulate the formulation of the security-constrained economic dispatch (SCED) in a test transmission network using the GAMS software, to show the nodal price variations due to the demand-side activities;

the other was to process a distributor's entire LV network data from geographic information system (GIS), based on the proposed modelling and simulation framework for carrying out impact assessments of SG control, protection and economic integration.

In the next three major chapters, three aspects of DSI were discussed in detail, which were distributor pricing structure, service quality differentiation and customer comfort expressed in DER availability respectively, to integrate various demand-side resources. The latter chapters, such as Chapter 6, consider more distribution regulation and policy elements, but require more supporting infrastructure, offering more network visibility and operation in real time. The earlier chapters, such as Chapter 4, are more practical, and could readily be implemented by minor changes or additions to some of the distribution regulations.

The distributor pricing structure, as demonstrated in Chapter 4, concluded that current profile and voltage drop were important considerations in the optimal network reinforcement planning, with deferred network investment evaluation achieved by controllable loads. In the case of PV penetration, reverse current profile was also an important factor, which was treated like serving load growth in the traditional distribution planning process. Based on the regulatory elements of capital return and consumer protection, pricing changes were proposed in the distribution pricing structure, to fairly reflect the network benefit of DER or required network support.

Going further beyond price differentiation, Chapter 5 explores the effect of service quality differentiation offered by SG technologies, such as electricity storage systems (ESS), controllable loads or distribution automation. The conventional network indices used were the load point reliability indices. The proposed payment of reliability premium (RP) to the distributor could indicate the individual customer's reliability preference explicitly, which also affected the load priorities in the load control dispatch algorithm that derives savings from wholesale market bidding. The pricing model proposed fit into the performance-based distribution regulations and the recently implemented demand-side bidding scheme in the wholesale market.

In addition to network voltage drop and current profile, Chapter 6 also recognised the diverse features of demand-side resources and the random usage patterns set by their owners. To maximise the accumulated time that a deferrable load can stay in the system to provide operational support without sacrificing the customer comfort level, the novel concept of 'time value' was proposed in the DER scheduling, instead of using the typical monetary terms. The proposed optimal network operation has achieved the maximum network utilisation and demand shaping strategy under the smart grid paradigm.

Overall, the current and upcoming electricity industry challenges have been considered throughout the thesis, which must be addressed within the regulatory framework and business environment. The thesis has contributed to the SG transition to DSI in the de-regulated electricity market. The thesis objective has been achieved from three distinctive but forward-looking perspectives, using different network parameters and conventional indices to develop three distribution pricing models that fit into the current or possible future regulatory framework. In conclusion, conventional power system analysis approaches have offered many parameters and indices, such as network voltage drop, current profile, load-point reliability indices, DER device energy and availability ('time value'). These parameters and indices were used to modify the existing distribution pricing models, to develop new pricing models, or to envision some future models while considering a combination of distribution network regulations.

7.2 Future directions

7.2.1 Demand-side integration (DSI) and distributed energy resources (DER)

The three aspects of DSI framework can be all extended in their own directions, by applying more detailed system data to produce specific results for the New Zealand cases. For example, smart meter data at the ICP level or network data with investment costs or reliability statistics.

In the direction of distributor pricing structure in Chapter 4, future work will include protection studies of high PV penetration scenarios to identify network issues and investment requirements during abnormal grid operation.

In the direction of service quality differentiation in Chapter 5, the effect of ageing underground cable replacement, battery installation or distribution automation needs to be considered when deriving the reliability premium.

In the direction of individual DER benefit reconciliation in Chapter 6, so far only ex-post reconciliation is considered. The possibility of quantifying DER benefit in real-time can be explored and compared to the methods proposed by others.

7.2.2 Transactive energy

As mentioned in the beginning of Chapter 1, the terminology has been constantly evolving to reflect the concurrent thinking at that time. When this thesis initially started, the term ‘demand-side integration’ has combined the popular topics of ‘demand response’ and ‘energy efficiency’. When the thesis was about to finish, the term ‘distributed energy resource’ started to dominate the literature. As it turns out that, the next trending topic will be around the term called ‘transactive energy’.

Interestingly, just when this thesis oral examination took place, IEEE Power & Energy Magazine published a collection of articles in the 2016 May/June issue to introduce the concept of ‘transactive energy’. The emerging role of ’distribution system operator’ (DSO) has been discussed in [161], which is to manage various distributed resources much like what a transmission system operator does. Some field implementations of transactive energy have already started in the US, with the New York state leading some of the initiatives as described in [162]. On the similar line of thinking as this thesis, [163] shows that the topic of transactive energy has to be addressed from many different perspectives, such as organisational, institutional, and technical layers, with different stakeholders such as regulators, utilities, service providers, and consumers/'prosumers'. In the future, various schedules and pricing singals will be exchanged among different entities around the DSO, as shown in [164], some of which were also addressed by the so-called 'pricing models' in this thesis, such as wholesale price signaling, customer preference, DSO instructions, and various contracts. From the view-point of system design architecture, [165] debates the two distinctive visions going forward, one is the centralised architecture to integrate DER into the wholesale market structure (much like what Chapter 5 proposed), while the other is the decentralised approach relying on the distributed agents (such as the HEMS proposed in Chapter 6). The complexity of transactive energy has been presented in [166], which invokes many energy-transaction-based terms, like DER adoption rates, retail rates, transmission & distribution (T&D) rates, T&D CapEx, T&D reliability, and customer reliability, as being discussed throughout this thesis. Lastly, the issue of regulatory policy and investment guideline is also discussed in [167], which favours regulatory changes that enable private investment in the distribution business.

Overall, the exciting topic of transactive energy has already started, to which this thesis was part of the initial discussions. Thus, the thesis has also laid the fundamental work of studying transactive energy, in the context of New Zealand Electricity Market, power systems and regulatory environment.

7.3 Publications

Two industry projects have been completed with the system operator - Transpower New Zealand, and the Auckland distributor - Vector Limited.

The complete list of academic publications is as following:

7.3.1 Peer-reviewed journal publications

1. 'Distributor "time value" pricing framework to schedule distributed energy resources'. Zhang Z & Nair N (2016). Submitted to International Transactions on Electrical Energy Systems.

2. 'Distributor pricing approaches enabled in smart grid to differentiate delivery service quality'. Zhang Z & Nair N (2014). ICST EAI Trans. on Energy Web, 14(3): e1. doi: dx.doi.org/10.4108/ew.1.3.e1

7.3.2 Peer-reviewed conference publications

1. 'Modelling and simulation framework for techno-economic analysis of large city low voltage distribution network'. Zhang Z, Nair N & Cross C (2015). IEEE PES ISGT Asia.

2. 'Economic regulation and pricing principle of photovoltaic integration technologies'. Zhang Z & Nair N (2015). EEA Conf., NZ.

3. 'Distribution use-of-system pricing to facilitate retail competition and demand management'. Zhang Z & Nair N (2014). IEEE PES General Meeting, USA. doi: 10.1109/PESGM.2014.6939380

4. 'Participation model for small customers using reliability preference in demand dispatch'. Zhang Z & Nair N (2013). IEEE PES General Meeting, Canada. doi: 10.1109/PESMG.2013.6672519

5. 'Analysis of transmission loss model in New Zealand Electricity Market dispatch'. Zhang Z, Goodwin D & Nair N (2013). IEEE AUPEC, Australia. doi: 10.1109/AUPEC.2013.6725430

6. 'Increasing the granularity of reliability assessment and CapEx classification for distribution network regulation'. Vegdani M, Zhang Z & Nair N (2013). EEA Conference, NZ.

7. ‘Economic and pricing signals in electricity distribution systems: A bibliographic survey’. Zhang Z & Nair N (2012). IEEE POWERCON, NZ. doi: 10.1109/PowerCon.2012.6401470

8. ‘Does New Zealand regulatory framework enable smart grid investments by distribution networks?’. Zhang Z & Nair N (2012). EEA Conf., NZ.

7.3.3 Invited presentations and articles

1. ‘Distribution utilities at a crossroad’. Nair N & Zhang Z (2014). IEEE Smart Grid Newsletter, Feb. http://smartgrid.ieee.org/newsletter/february-2014/distribution-utilities-at-a-crossroad

2. ‘Enabling increased value for wind generation in New Zealand electricity market’. Zhang Z (2013). NZWEA Conf., NZ.

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Appendices: test network data

IEEE 30-bus transmission test system

Base MVA: $S_b = 100$ MVA

Bus data

m	PD_m MW	PQ_m MVAr	Inject MVAr	Base kV	m	PD_m MW	PQ_m MVAr	Inject MVAr	Base kV
1	0	0	0	132	16	3.5	1.8	0	33
2	21.7	12.7	0	132	17	9	5.8	0	33
3	2.4	1.2	0	132	18	3.2	0.9	0	33
4	7.6	1.6	0	132	19	9.5	3.4	0	33
5	0	0	0	132	20	2.2	0.7	0	33
6	0	0	0	132	21	17.5	11.2	0	33
7	22.8	10.9	0	132	22	0	0	0	33
8	30	10	0	132	23	3.2	1.6	0	33
9	0	0	0	1	24	8.7	6.7	4.3	33
10	5.8	2	19	33	25	0	0	0	33
11	0	0	0	11	26	3.5	2.3	0	33
12	11.2	7.5	0	33	27	0	0	0	33
13	0	0	0	11	28	0	0	0	132
14	6.2	1.6	0	33	29	2.4	0.9	0	33
15	8.2	2.5	0	33	30	10.6	1.9	0	33

Branch data

j	m	m'	Resistance p.u.	Reactance p.u.	Susceptance p.u.	Capacity MVA	Off-turns ratio
1	1	2	0.0192	0.0575	0.0528	130	0
2	1	3	0.0452	0.1652	0.0408	130	0
3	2	4	0.057	0.1737	0.0368	65	0
4	3	4	0.0132	0.0379	0.0084	130	0
5	2	5	0.0472	0.1983	0.0418	130	0
6	2	6	0.0581	0.1763	0.0374	65	0
7	4	6	0.0119	0.0414	0.009	90	0
8	5	7	0.046	0.116	0.0204	70	0
9	6	7	0.0267	0.082	0.017	130	0
10	6	8	0.012	0.042	0.009	32	0
11	6	9	0	0.208	0	65	0.978
12	6	10	0	0.556	0	32	0.969
13	9	11	0	0.208	0	65	0
14	9	10	0	0.11	0	65	0
15	4	12	0	0.256	0	65	0.932
16	12	13	0	0.14	0	65	0
17	12	14	0.1231	0.2559	0	32	0
18	12	15	0.0662	0.1304	0	32	0
19	12	16	0.0945	0.1987	0	32	0
20	14	15	0.221	0.1997	0	16	0
21	16	17	0.0524	0.1923	0	16	0
22	15	18	0.1073	0.2185	0	16	0
23	18	19	0.0639	0.1292	0	16	0
24	19	20	0.034	0.068	0	32	0
25	10	20	0.0936	0.209	0	32	0
26	10	17	0.0324	0.0845	0	32	0
27	10	21	0.0348	0.0749	0	32	0
28	10	22	0.0727	0.1499	0	32	0

j	m	m'	Resistance p.u.	Reactance p.u.	Susceptance p.u.	Capacity MVA	Off-turns ratio
29	21	22	0.0116	0.0236	0	32	0
30	15	23	0.1	0.202	0	26	0
31	22	24	0.115	0.179	0	16	0
32	23	24	0.132	0.27	0	16	0
33	24	25	0.1885	0.3292	0	16	0
34	25	26	0.2544	0.38	0	16	0
35	25	27	0.1093	0.2087	0	17	0
36	28	27	0	0.396	0	65	0.968
37	27	29	0.2198	0.4153	0	16	0
38	27	30	0.3202	0.6027	0	16	0
39	29	30	0.2399	0.4533	0	16	0
40	8	28	0.0636	0.2	0.0428	32	0
41	6	28	0.0169	0.0599	0.013	32	0

IEEE 123-node distribution test network

Line segment data

f	m	m'	Length(m)	Config.	f	m	m'	Length(m)	Config.
1	1	2	53.34	10	59	60	61	167.64	5
2	1	3	76.2	11	60	60	62	76.2	12
3	1	7	91.44	1	61	62	63	53.34	12
4	3	4	60.96	11	62	63	64	106.68	12
5	3	5	99.06	11	63	64	65	129.54	12
6	5	6	76.2	11	64	65	66	99.06	12
7	7	8	60.96	1	65	67	68	60.96	9
8	8	12	68.58	10	66	67	72	83.82	3
9	8	9	68.58	9	67	67	97	76.2	3
10	8	13	91.44	1	68	68	69	83.82	9
11	9	14	129.54	9	69	69	70	99.06	9
12	13	34	45.72	11	70	70	71	83.82	9
13	13	18	251.46	2	71	72	73	83.82	11
14	14	11	76.2	9	72	72	76	60.96	3
15	14	10	76.2	9	73	73	74	106.68	11
16	15	16	114.3	11	74	74	75	121.92	11
17	15	17	106.68	11	75	76	77	121.92	6
18	18	19	76.2	9	76	76	86	213.36	3
19	18	21	91.44	2	77	77	78	30.48	6
20	19	20	99.06	9	78	78	79	68.58	6
21	21	22	160.02	10	79	78	80	144.78	6
22	21	23	76.2	2	80	80	81	144.78	6
23	23	24	167.64	11	81	81	82	76.2	6
24	23	25	83.82	2	82	81	84	205.74	11
25	25	26	106.68	7	83	82	83	76.2	6
26	25	28	60.96	2	84	84	85	144.78	11
27	26	27	83.82	7	85	86	87	137.16	6

f	m	m'	Length(m)	Config.	f	m	m'	Length(m)	Config.
28	26	31	68.58	11	86	87	88	53.34	9
29	27	33	152.4	9	87	87	89	83.82	6
30	28	29	91.44	2	88	89	90	68.58	10
31	29	30	106.68	2	89	89	91	68.58	6
32	30	250	60.96	2	90	91	92	91.44	11
33	31	32	91.44	11	91	91	93	68.58	6
34	34	15	30.48	11	92	93	94	83.82	9
35	35	36	198.12	8	93	93	95	91.44	6
36	35	40	76.2	1	94	95	96	60.96	10
37	36	37	91.44	9	95	97	98	83.82	3
38	36	38	76.2	10	96	98	99	167.64	3
39	38	39	99.06	10	97	99	100	91.44	3
40	40	41	99.06	11	98	100	450	243.84	3
41	40	42	76.2	1	99	101	102	68.58	11
42	42	43	152.4	10	100	101	105	83.82	3
43	42	44	60.96	1	101	102	103	99.06	11
44	44	45	60.96	9	102	103	104	213.36	11
45	44	47	76.2	1	103	105	106	68.58	10
46	45	46	91.44	9	104	105	108	99.06	3
47	47	48	45.72	4	105	106	107	175.26	10
48	47	49	76.2	4	106	108	109	137.16	9
49	49	50	76.2	4	107	108	300	304.8	3
50	50	51	76.2	4	108	109	110	91.44	9
51	52	53	60.96	1	109	110	111	175.26	9
52	53	54	38.1	1	110	110	112	38.1	9
53	54	55	83.82	1	111	112	113	160.02	9
54	54	57	106.68	3	112	113	114	99.06	9
55	55	56	83.82	1	113	135	35	114.3	4
56	57	58	76.2	10	114	149	1	121.92	1
57	57	60	228.6	3	115	152	52	121.92	1

f	m	m'	Length(m)	Config.	f	m	m'	Length(m)	Config.
58	58	59	76.2	10	116	160	67	106.68	6
					117	197	101	76.2	3

Spot loads

Node	Load Model	Ph-1 kW	Ph-1 kVAr	Ph-2 kW	Ph-2 kVAr	Ph-3 kW	Ph-4 kVAr
1	Y-PQ	40	20	0	0	0	0
2	Y-PQ	0	0	20	10	0	0
4	Y-PR	0	0	0	0	40	20
5	Y-I	0	0	0	0	20	10
6	Y-Z	0	0	0	0	40	20
7	Y-PQ	20	10	0	0	0	0
9	Y-PQ	40	20	0	0	0	0
10	Y-I	20	10	0	0	0	0
11	Y-Z	40	20	0	0	0	0
12	Y-PQ	0	0	20	10	0	0
16	Y-PQ	0	0	0	0	40	20
17	Y-PQ	0	0	0	0	20	10
19	Y-PQ	40	20	0	0	0	0
20	Y-I	40	20	0	0	0	0
22	Y-Z	0	0	40	20	0	0
24	Y-PQ	0	0	0	0	40	20
28	Y-I	40	20	0	0	0	0
29	Y-Z	40	20	0	0	0	0
30	Y-PQ	0	0	0	0	40	20
31	Y-PQ	0	0	0	0	20	10
32	Y-PQ	0	0	0	0	20	10
33	Y-I	40	20	0	0	0	0
34	Y-Z	0	0	0	0	40	20

Node	Load Model	Ph-1 kW	Ph-1 kVAr	Ph-2 kW	Ph-2 kVAr	Ph-3 kW	Ph-4 kVAr
35	D-PQ	40	20	0	0	0	0
37	Y-Z	40	20	0	0	0	0
38	Y-I	0	0	20	10	0	0
39	Y-PQ	0	0	20	10	0	0
41	Y-PQ	0	0	0	0	20	10
42	Y-PQ	20	10	0	0	0	0
43	Y-Z	0	0	40	20	0	0
45	Y-I	20	10	0	0	0	0
46	Y-PQ	20	10	0	0	0	0
47	Y-I	35	25	35	25	35	25
48	Y-Z	70	50	70	50	70	50
49	Y-PQ	35	25	70	50	35	20
50	Y-PQ	0	0	0	0	40	20
51	Y-PQ	20	10	0	0	0	0
52	Y-PQ	40	20	0	0	0	0
53	Y-PQ	40	20	0	0	0	0
55	Y-Z	20	10	0	0	0	0
56	Y-PQ	0	0	20	10	0	0
58	Y-I	0	0	20	10	0	0
59	Y-PQ	0	0	20	10	0	0
60	Y-PQ	20	10	0	0	0	0
62	Y-Z	0	0	0	0	40	20
63	Y-PQ	40	20	0	0	0	0
64	Y-I	0	0	75	35	0	0
65	D-Z	35	25	35	25	70	50
66	Y-PQ	0	0	0	0	75	35
68	Y-PQ	20	10	0	0	0	0
69	Y-PQ	40	20	0	0	0	0
70	Y-PQ	20	10	0	0	0	0

Node	Load Model	Ph-1 kW	Ph-1 kVAr	Ph-2 kW	Ph-2 kVAr	Ph-3 kW	Ph-4 kVAr
71	Y-PQ	40	20	0	0	0	0
73	Y-PQ	0	0	0	0	40	20
74	Y-Z	0	0	0	0	40	20
75	Y-PQ	0	0	0	0	40	20
76	D-I	105	80	70	50	70	50
77	Y-PQ	0	0	40	20	0	0
79	Y-Z	40	20	0	0	0	0
80	Y-PQ	0	0	40	20	0	0
82	Y-PQ	40	20	0	0	0	0
83	Y-PQ	0	0	0	0	20	10
84	Y-PQ	0	0	0	0	20	10
85	Y-PQ	0	0	0	0	40	20
86	Y-PQ	0	0	20	10	0	0
87	Y-PQ	0	0	40	20	0	0
88	Y-PQ	40	20	0	0	0	0
90	Y-I	0	0	40	20	0	0
92	Y-PQ	0	0	0	0	40	20
94	Y-PQ	40	20	0	0	0	0
95	Y-PQ	0	0	20	10	0	0
96	Y-PQ	0	0	20	10	0	0
98	Y-PQ	40	20	0	0	0	0
99	Y-PQ	0	0	40	20	0	0
100	Y-Z	0	0	0	0	40	20
102	Y-PQ	0	0	0	0	20	10
103	Y-PQ	0	0	0	0	40	20
104	Y-PQ	0	0	0	0	40	20
106	Y-PQ	0	0	40	20	0	0
107	Y-PQ	0	0	40	20	0	0
109	Y-PQ	40	20	0	0	0	0

Node	Load Model	Ph-1 kW	Ph-1 kVAr	Ph-2 kW	Ph-2 kVAr	Ph-3 kW	Ph-4 kVAr
111	Y-PQ	20	10	0	0	0	0
112	Y-I	20	10	0	0	0	0
113	Y-Z	40	20	0	0	0	0
114	Y-PQ	20	10	0	0	0	0
Total		1420	775	915	515	1155	630

Transformer data

	kVA	kV-high	kV-low	R - %	X - %
Substation	5,000	115 - D	4.16 Gr-W	1	8
XFM - 1	150	4.16 - D	.480 - D	1.27	2.72

Shunt capacitors

m	Ph-A (kVAr)	Ph-B (kVAr)	Ph-C (kVAr)
83	200	200	200
88	50	0	0
90	0	50	0
92	0	0	50

Overhead line configurations

Config.	Phasing	Phase cond. ACSR	Neutral cond. ACSR	Spacing ID
1, 2, 3	A B C N, C A B N, B C A N	336,400 26/7	4/0 6/1	500
4, 5, 6	C B A N, B A C N, A C B N	336,400 26/7	4/0 6/1	500
7, 8	A C N, A B N	336,400 26/7	4/0 6/1	505
9, 10, 11	A N, B N, C N	1/0	1/0	510

Underground line configuration

Config.	Phasing	Cable	Spacing ID
12	A B C	1/0 AA, CN	515

Three-phase switches

Normally	m	13	18	60	61	97	150
closed	m'	152	135	160	610	197	149

Normally	m	250	450	54	151	300
open	m'	251	451	94	300	350

Regulator data

Regulator ID:	1	2	3	4
Line Segment:	150 - 149	9 - 14	25 - 26	160 - 67
Location:	150	9	25	160
Phases:	A-B-C	A	A-C	A-B-C
Connection:	3-Ph, Wye	1-Ph, L-G	2-Ph,L-G	3-Ph, LG
Monitoring Phase:	A	A	A & C	A-B-C
Bandwidth:	2.0 volts	2.0 volts	1	2
PT Ratio:	20	20	20	20
Primary CT Rating:	700	50	50	300
Compensator:	Ph-A	Ph-A	Ph-A, Ph-C	Ph-A, Ph-B, Ph-C
R - Setting:	3	0.4	0.4, 0.4	0.6, 1.4, 0.2
X - Setting:	7.5	0.4	0.4, 0.4	1.3, 2.6, 1.4
Voltage Level:	120	120	120, 120	124, 124, 124

IEEE 4-bus test distribution network

Feeder lengths

- Feeders between nodes 1-2, 1-3, 1-4: 609.6m
- Feeders between nodes 5-8, 6-9, 7-10: 762m

Spacing: AB: 6.35cm, BC: 11.43cm, AC: 17.78cm, AN: 14.37cm, BN: 10.85cm, CN: 12.7cm

Conductors

- Phase: 336,400 26/7, GMR 0.7437cm, resistance 0.1901 Ω/km, diameter 1.8313cm
- Neutral: 4/0 6/1 ACSR, GMR 0.2481cm, resistance 0.3679 Ω/km, diameter 1.43cm

Three-phase transformers: 6000kVA, V_{LL} high 12.47kV, V_{LL} low 4.16kV, R 1.0%, X 6.0%

Peak loads: phase-1, phase-2, phase-3 all 1800kW, 0.9 lag

IEEE RBTS distribution network Bus No. 2

Base case load point reliability indices

	cables			lines		
	λ_m	r_m	$\lambda_m \cdot r_m$	λ_m	r_m	$\lambda_m \cdot \gamma_m$
m	(/yr)	(hour)	(hour/yr)	(/yr)	(hour)	(hour/yr)
1	0.153	31.84	4.87	0.24	14.9	3.58
2	0.161	31.75	5.11	0.253	14.4	3.64
3	0.161	31.75	5.11	0.253	14.4	3.64
4	0.153	31.84	4.87	0.24	14.9	3.58
5	0.161	31.75	5.11	0.253	14.4	3.64
6	0,159	31.77	5.05	0.25	14.51	3.63
7	0.161	30.75	4.95	0.253	14.24	3.6
8	0.086	22.47	1.93	0.14	3.89	0.54
9	0.086	20.58	1.77	0.14	3.6	0.5
10	0.155	31.47	4.88	0.243	14.73	3.58
11	0.161	31.75	5.11	0.253	14.4	3.64
12	0.163	31.73	5.17	0.256	14.29	3.66
13	0.161	30.41	4.9	0.253	14.19	3.59
14	0.163	30.41	4.96	0.256	14.08	3.61
15	0.155	31.47	4.88	0.243	14.73	3.58
16	0.161	31.75	5.11	0.253	14.4	3.64
17	0.155	31.82	4.93	0.243	14.78	3.59
18	0.155	31.47	4.88	0.243	14.73	3.58
19	0.163	31.4	5.12	0.256	14.24	3.65
20	0.163	31.4	5.12	0.256	14.24	3.65
21	0.161	30.41	4.9	0.253	14.19	3.59
22	0.163	30.41	4.96	0.256	14.08	3.61

Feeder lengths

Feeder section numbers, j	Length (km)
2, 6, 10, 14, 17, 21, 25, 28, 30, 34	0.6
1, 4, 7, 9, 12, 16, 19, 22, 24, 27, 29, 32, 35	0.75
3, 5, 8, 11, 13, 15, 18, 20, 23, 26, 31, 33, 36	0.8