Power system adequacy and cost/worth assessment incorporating virtual power plants

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**NANYANG
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UNIVERSITY**

SINGAPORE

**POWER SYSTEM ADEQUACY AND COST/WORTH
ASSESSMENT INCORPORATING VIRTUAL POWER
PLANTS**

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POWER SYSTEM ADEQUACY AND COST/WORTH ASSESSMENT INCORPORATING VIRTUAL POWER PLANTS

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A thesis submitted to the Nanyang Technological University in partial fulfilment of the
requirements for the degree of

DOCTOR OF PHILOSOPHY

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*Dedicated to my grandmother Jayanti who passed away during the course of my PhD studies, and
who I wish was here to see me bring my dreams to fruition*

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SUMMARY

A variety of factors such as the emergence of novel business models in deregulated power markets, adoption of smart grid technologies, economic recession as well as climate change has led to a proliferation of distributed energy resources (DER) in low and medium voltage power networks over the last decade. The DER portfolio can consist of any given combination of renewable and/or conventional source based distributed generators (DG), energy storage devices (ESD) as well as controllable loads. Today's distribution networks are therefore gradually getting transformed from their traditional 'passive' roles to an 'active' system featuring advanced coordination and control of its constituent DER components and protection equipment. Indiscriminate addition of DERs on the demand side, however, poses a number of visibility and security related challenges for the system operators, primarily owing to the modest capacities most DERs possess (a few kW to a few MW) coupled with the inherent intermittencies associated with renewable resources. The concept of aggregating several active distribution network components like DERs and loads in the form of a virtual power plant (VPP) has therefore often been proposed for tackling the above mentioned challenges.

In the available literature pertaining to the reliability evaluation of power systems incorporating VPPs, the system studies are all carried out at the distribution network level, meaning that they fail to quantify the average energy that the VPP can export to the transmission grid after meeting local distribution network demands and constraints. Additionally, the evaluation of system reliability at the distribution level does not adequately portray the possible improvements which can be brought about in the overall system reliability due to the injection of excess energy into the external grid by the VPP. Moreover, a holistic planning approach for determining an optimal DER portfolio for the VPP so as to minimize its total operating, investment and interruption costs while considering transmission network constraints and contingencies has not been explored. This thesis addresses these limitations by proposing generic methodologies for performing generation and bulk power system adequacy and cost/worth assessments incorporating VPPs.

The first contribution of this research work is the proposal of a Monte Carlo simulation based methodology for performing adequacy assessment of generating systems incorporating VPPs. The disparate operating characteristics as well as capacities of individual DGs and local loads along with information about distribution network features like topology and constraints are combined together to form an equivalent model of a VPP using a linearized network flow based optimization formulation. The VPP is mathematically represented as a single entity with respect to the transmission grid, and its 'prosumer' (producer/consumer) characteristics are portrayed using a probability density function. The

equivalent VPP model is used in conjunction with several new indices introduced for quantifying different aspects of the VPP's performance. Key reliability indices are presented for quantifying the VPP's contributions in improving overall system reliability.

A general methodology for investigating the impacts of incorporating ESDs into the VPP model mentioned above, and subsequently using this model for performing generation adequacy studies is proposed next as the second contribution of this research work. A linear programming based multi-stage optimization formulation is presented for combining the stochastic hourly-output based models of several DGs, ESDs and loads along with distribution network features like topology and constraints into an aggregated probabilistic representation of the VPP. Several modes pertaining to the charging/discharging of the distributed ESDs are integrated with the formulation using a fair energy allocation based operating strategy. The VPP performance indices mentioned above are suitably modified for quantifying the impacts of the ESDs' incorporation into the VPP profile.

A systematic procedure is introduced as the third contribution of this research work for assessing bulk power system adequacy incorporating the equivalent VPP model (including ESDs) developed above. A linearized DC load flow based optimal power flow (OPF) formulation is proposed for performing transmission network contingency analysis. The OPF problem minimizes the total load curtailment and generation costs for the system, while also enabling priority dispatch of the VPP output (if available) into the external grid. The VPP performance indices are suitably modified for highlighting the impacts of transmission grid constraints and contingencies on the VPP profile, and it is shown that the severity of these impacts is a function of the VPP's location in the transmission grid under consideration. The effects of the VPP's incorporation on reliability at the system and at individual transmission bus levels are also quantified using key bulk power system adequacy indices.

The DC load flow based OPF formulation described above is then combined with composite system cost/worth analysis techniques for determining an optimal DER portfolio for the VPP so as to minimize the total perceived costs pertaining to the VPP's participation in day-ahead electricity markets. This constitutes the fourth and final contribution of this research work. The costs associated with the VPP are sub-divided into five categories – import, customer interruption, operation, investment and revenues – and different DER configurations are examined to determine the optimal portfolio which offers the highest cost savings for the VPP aggregator. Depending on the VPP's location in the transmission grid under consideration, the performed simulations demonstrate that the optimal DER portfolio offers the VPP aggregator an estimated cost savings in the range of 414.69 k\$/year – 620.92 k\$/year.

The overall methodologies proposed in this thesis are tested using the Roy Billinton Test System (RBTS) as well as the IEEE Reliability Test System (RTS). Two distribution network test beds are separately used for modelling the VPP: the RBTS Bus 4 distribution network and the (larger) IEEE 69-

bus distribution network. Sequential Monte Carlo techniques are employed for performing the simulations. Extensive sensitivity studies are performed and several extensions to the work done in this project are listed as potential areas of future research. The results presented in this thesis can not only provide valuable information to the VPP aggregator and the system operator regarding important facets of the VPP's performance, but also offer them critical insights pertaining to the economic benefits which can be obtained from incorporating VPPs into existing power networks.

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LIST OF ACRONYMS

AR(I)MA	Auto-Regressive (Integrated) Moving Average
CCDF	Composite Customer Damage Function
DA	Day-Ahead
DER	Distributed Energy Resource
DG	Distributed Generator
DNO	Distribution Network Operator
EDLC	Expected Duration of Load Curtailments
EENS	Expected Energy Not Supplied
EFLC	Expected Frequency of Load Curtailments
ERENU	Expected Renewable Energy Not Used
ESD	Energy Storage Device
ESGD	Expected System Generation Displaced
ESGS	Expected System Generation Supplemented
HLI	Hierarchical Level I
HLII	Hierarchical Level II
IEAR	Interrupted Energy Assessment Rate
ISO	Independent System Operator
LOEE	Loss of Energy Expectation
LOLE	Loss of Load Expectation
LOLF	Loss of Load Frequency
MTTR	Mean Time to Repair
MVPPE	Mean VPP Export
OPF	Optimal Power Flow
PDF	Probability Density Function
RBTS	Roy Billinton Test System
RTS	Reliability Test System
SoC	State-of-Charge
VPP	Virtual Power Plant
WTG	Wind Turbine Generator

LIST OF VARIABLES

Chapter 2:

i	Given hour of sequential simulation algorithm
j	Given year of sequential simulation algorithm
t_{ij}	Binary variable, 1 when system transits from success state in hour 'i-1' to failure state in hour 'i', 0 otherwise
m_{ij}	Binary variable, 1 when total system generation is less than demand, 0 otherwise
N_y	Total number of simulation years required for sequential algorithm convergence
α_i	Normal white noise parameter
σ_i	Mean observed wind speed
μ_i	Standard deviation of observed wind speed
$P_{G,ij}$	Total system generation
$P_{D,ij}$	Total system demand
y_i	Normalized wind speed
OW_i	Observed wind speed
SW_i	Simulated wind speed
P_r	WTG rated capacity
V_r	WTG rated wind speed
V_{ci}	WTG cut-in wind speed
V_{co}	WTG cut-out wind speed
SSR_i	Simulated solar irradiance
NOCT	Nominal operating cell temperature for PV module
$P_{w,i}$	WTG power output
$P_{s,i}$	PV system power output
FF	Fill factor of PV modules
k_v	Voltage temperature coefficient characterizing PV module
k_i	Current temperature coefficient characterizing PV module
V_{MPP}	Maximum power point voltage characterizing PV module
I_{MPP}	Maximum power point current characterizing PV module
V_{oc}	Open circuit voltage characterizing PV module
I_{sc}	Short circuit current characterizing PV module
$T_{c,i}$	PV cell temperature
$T_{a,i}$	PV module ambient temperature

Chapter 3:

N	Set of all nodes in distribution network
K	Set of all DGs in distribution network
L	Set of all lines in distribution network
w^r	Weight assigned to renewable DG curtailments
w^c	Weight assigned to conventional DG curtailments
$C_{k,ij}^r$	Renewable DG curtailments
$C_{k,ij}^c$	Conventional DG curtailments
$P_{l,n,ij}^{in}$	Incoming line flow at distribution network node 'n'
$P_{l,n,ij}^{out}$	Outgoing line flow at distribution network node 'n'
$G_{k,ij}$	DG power output
$C_{k,ij}$	DG curtailment
$G_{k,n,ij}$	Power output of DG at distribution network node 'n'
$G_{k,max,ij}$	DG maximum power output
$P_{l,ij}$	Power flow through distribution feeder
$P_{l,max}$	Maximum power rating of distribution feeder
$D_{n,ij}$	Demand at distribution network node 'n'
$P_{VPP,ij}$	Optimal VPP output at transmission grid interface

Chapter 4:

S	Set of all ESDs in distribution network
$E_{max,s}$	Maximum energy consumed by/dispatched from ESD
$E_{R,s}$	ESD rated capacity
T_{ch}	ESD charging period
T_d	ESD discharging period
SoC_{min}	Minimum state-of-charge of ESD
SoC_{max}	Maximum state-of-charge of ESD
η_{ch}	ESD charging efficiency
η_d	ESD discharging efficiency
w^s	Weight assigned to ESD optimal curtailment variable
$C_{s,ij}$	Optimal curtailment from ESD
$E_{max,s,ij}^{ch}$	Charging energy requirement from ESD
$E_{max,s,ij}^d$	Dispatchable energy from ESD

$E_{s,ij}$	Stored energy in ESD in hour ‘i’
$P_{0,ij}$	Optimal VPP output at transmission grid interface after incorporating ESDs
Z_j	Standard normal variable
σ	Standard deviation of forecast peak load
$P_{D,peak,j}$	Forecast annual peak load
$P_{D,peak,j}^{unc}$	Annual peak load incorporating load forecast uncertainty
$P_{D,ij}^{unc}$	Hourly demand incorporating load forecast uncertainty

Chapter 5:

B	Set of all buses in transmission network
B_D	Set of load buses in transmission network
T	Set of transmission lines in transmission network
G	Set of grid-connected generators in transmission network
N_b	Total number of buses in transmission network
λ_b	IEAR associated with load bus
λ_g	Incremental production cost of generating unit
$C_{b,ij}$	Optimal curtailment at load bus
$P_{dis,g,ij}$	Optimal dispatch from generating unit
$P_{inj,VPP,ij}$	Optimal power injection at VPP’s transmission grid interface after incorporating transmission network constraints and contingencies
$P_{D,b,ij}$	Load bus demand
$P_{g,max,ij}$	Maximum output of generating unit
A	Relationship matrix between line flows and power injections
$P_{t,ij}$	Power flow through transmission line
$P_{t,max}$	Maximum power rating of transmission line
$G_{VPP,ij}$	Total energy injection of VPP for meeting system demand

Chapter 6:

$\lambda_{e,ij}$	Uniform marginal price for clearing day-ahead market
dur_{I_s}	Duration of interruption sequence ‘ I_s ’
$\lambda_{I_s}(dur_{I_s})$	Normalized interruption cost for interruption duration
π_{imp}	Expected annual import cost
π_{int}	Expected annual interruption cost
C_{VPP,I_s}^{avg}	Average VPP load curtailment in interruption sequence

N_{int}	Total number of interruption sequences over course of simulation
π_{rv}	Expected annual revenues
π_{o}	Expected annual operating cost
π_{inv}	Annual investment cost
$\pi_{\text{tot},\omega}$	Total expected annual cost pertaining to VPP's participation in DA market for a given scenario, sub-scenario combination ' ω '
π_{sav}	VPP aggregator's expected annual cost savings after incorporating optimal DER portfolio

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CHAPTER 1

INTRODUCTION

1.1. Overview

A surge in global energy demand owing to rising population and increased industrialization over the last few decades has led to a steady depletion of fossil fuel resources, e.g. coal, petroleum and natural gas. Concerns over the excessive use of fossil fuels and their impact on global warming have, for a long time, shaped our increased interest in the use of greener and cleaner forms of energy. The World Energy Outlook 2016 report released by the International Energy Agency predicts an increase of 30% in the global energy demand till 2040, which will necessitate additional investments in new generation capacity [1]. Renewables are predicted to account for about 60% of the total power generated in 2040, with almost half of this coming from wind and PV systems alone [1–2]. While growth in oil and coal end-use will rapidly decline over this period, natural gas consumption is expected to increase by about 50% [1]. Demands for coal in the European Union and the United States are expected to decline by around 60% and 40% respectively over the period until 2040 [1].

Factors such as the gradual unbundling of power sector entities in deregulated markets, sustained advancements made in renewable generation technologies, increased affordability of renewable generation equipment as well as tightening of most federal budgets owing to global recession have led governments worldwide to progressively shift focus from building large centralized fossil-fuelled power plants to gradually empowering consumers to take charge of their energy needs in an environment-friendly manner. This has led to the proliferation of small-scale distributed energy resources (DER) in low and medium voltage power networks over the last decade. 28% of the investments made in the renewable sector in 2013 went towards the augmentation of small-scale distributed generation capacity [3]. City councils and municipalities across the globe have increasingly started implementing strategies for promoting the generation and use of renewable energy in local communities. For instance, an estimated 508 MW of community-owned renewable generation capacity existed in Scotland in 2015, exceeding the government's target of 500 MW capacity by 2020 [4]. Increased penetration of distributed generation in local and regional communities has several advantages, namely, the improvement of local air quality, increased self-sufficiency of local communities in meeting their own demands as well as the possibility of generating revenues and creating local jobs [4].

In spite of the many advantages related to the harnessing of clean energy from renewable resources, uncontrolled and indiscriminate addition of DERs on the demand side poses a serious challenge for system operators. Most DERs have a small to medium sized capacity (a few kW to a few

MW), and are as such mostly ‘invisible’ to the grid [5]. This means that owing to their small size, the system operator cannot easily take the contribution of individual DERs into account while drawing up unit commitment schedules. Additionally, due to the inherent intermittency associated with renewable resources, the system operator needs to provide for adequate spinning reserves in order to maintain acceptable levels of network security [6]. This in turn leads to under-utilization of assets, reduction in system efficiency as well as increased electricity tariffs for end-users [7].

Apart from the above mentioned ‘system-oriented’ problems associated with DERs, there are also some issues from the point of view of the DER owners. Owing to their small capacity, intermittency, scattered locations across the grid as well as lack of proper communication with the system operator, it becomes extremely difficult for these individual owners to profitably trade their energy in the wholesale electricity markets [6]. This limitation in being able to fully unlock the financial potential of DERs makes it difficult from an individual owner’s perspective to justify these investments in the absence of government subsidies and incentives.

In order to tackle the above mentioned challenges, many researchers [5–9] have proposed the idea of aggregating several distributed generators (renewable and/or fossil fuel based), storage devices as well as flexible loads into a cooperative structure called virtual power plant (VPP). As of today, such cooperative entities are already operating in countries across the world, e.g., Germany, Costa Rica, Chile and Nepal [4]. Also, the United States has several ‘community solar gardens’ which pool in energy from individual rooftop installations and sell excess power to local utilities which in turn provide monthly credits to contributing households [3].

This thesis proposes generic methodologies for performing generation and bulk power system adequacy and cost/worth assessments incorporating an aggregated probabilistic model of DERs and loads under the umbrella of a VPP. The DER portfolio modelled in this study comprises small-scale distributed wind turbine generators (WTG), PV systems, gas-fired micro-turbines as well as energy storage devices (ESD). The VPP concept adopted in this thesis therefore refers to the aggregated representation of the disparate operating characteristics and capacities of the DERs and loads along with associated distribution network information like topology and constraints. The aggregation is done at the distribution network’s point of common coupling with the transmission grid, which means that for an observer on the external grid side, the VPP model’s characteristics resemble those of a conventional power plant. This concept is somewhat close to that of a ‘microgrid’, however, the following are some key differentiators between the two ideas. While a microgrid mostly refers to an aggregation of DERs and loads on a small scale (perhaps a single or a few adjacent distribution feeders), a VPP’s DER portfolio can typically consist of resources that are geographically dispersed (perhaps at different transmission buses) [9]. With this in mind, while a microgrid’s economic assessment mostly relates to analysing its capability to provide energy and

ancillary services to the local distribution utility and/or customers, one of the key challenges facing the VPP aggregator is to optimize the resources in its (geographically dispersed) DER portfolio so as to maximize its profits by trading surplus energy in wholesale electricity markets [9]. Chapter 6 of this thesis indeed presents a VPP planning strategy from a composite system cost/worth perspective, wherein an optimal DER portfolio is determined for minimizing the total perceived costs (and hence maximizing the cost savings) pertaining to the VPP's participation in day-ahead electricity markets. It is to be noted that the VPP is modelled in this thesis using a single distribution network assumed to be connected to a given transmission bus only at any time. The methodologies presented in this thesis for developing the VPP model are however generic, and can be easily extended to adequacy assessments that incorporate VPPs managing multiple energy resources dispersed across the transmission grid. This idea is indeed listed in Chapter 7 as a potential area of future research.

1.2. Research Motivations

Several deficiencies exist in the current literature [10–21] pertaining to the adequacy and cost/worth evaluations of power systems incorporating an aggregated model of DERs and loads in the form of a VPP. A detailed analytical approach for performing reliability evaluation of distribution systems including DERs is presented in [12], wherein the authors present comprehensive formulations for computing the annual outage rates and outage durations of various load points due to the occurrence of faults on different distribution feeder sections. The impact of correlations between the DER power outputs and load point demands is investigated in the distribution network reliability evaluation study [13]. An innovative analytical methodology for assessing the reliability of a distribution system including DERs is described in [14], wherein the authors use universal generating functions for representing individual DER components like PV systems, WTGs and electric vehicles as multi-state models, while taking into consideration random failures as well as the inherent intermittencies associated with these components. Reference [15] is one of the first papers to combine a group of DERs and local loads into a VPP model and incorporate it into the overall proposed distribution network reliability assessment procedure. A similar reliability analysis of distribution networks incorporating DERs is described in [16], wherein the authors introduce zoning and minimal path search techniques for efficient execution of the state sampling algorithm. A sequential simulation based adequacy assessment procedure for distribution systems including distributed generation (DG), ESDs and flexible loads participating in demand response programs is presented in [17], making use of the concepts of customer benefit function and the coefficient of price elasticity. A comprehensive reliability assessment methodology for active distribution networks is presented in [18–19], wherein the authors make use of detailed network aggregation techniques for representing low and medium voltage networks by their reliability equivalent models. The authors in [20]

introduce a model-predictive control based operating strategy for minimizing the annual energy import cost for distribution networks containing DGs and ESDs, while also incorporating an islanding operation methodology for reducing the network's customer interruption costs. A planning strategy for determining the optimal sizing and siting of DGs in a distribution network is presented in [21], while minimizing the total cost incurred by the network as expressed by the sum of DG investment, operation, maintenance and customer interruption costs coupled with penalties for power quality fluctuations and feeder losses.

As is evident from the discussions above, the system adequacy studies in most of these publications are performed at the distribution level. The proposed methodologies in these publications are based on a basic working principle that while local demand is met as long as the distribution network load points are connected to the external grid, some/all demand may need to be curtailed in the event that an island is formed after a contingency and DER output is insufficient to satisfy local demand. Since one of the major driving forces behind the introduction of the concept of VPPs is to increase the profitability and competitiveness of individual DERs through enhanced visibility and access when participating as a group in electricity markets, references [12–21] fail to capture a key point in their analyses: quantification of the average energy that the VPP can export to the external grid after meeting local distribution system demand. Therefore, the basic focus of the research work reported in this thesis is to propose generic methodologies for performing generation and bulk power system adequacy and cost/worth assessments incorporating an aggregated probabilistic model of DERs and loads under the umbrella of a VPP, thus quantifying the contribution of the VPP as a single entity to the external grid.

Another point to observe from references [12–21] is that the quantification of system reliability is done using indices computed for individual load points as well as at the distribution bus level, as a result of which only the local contributions of demand side DERs in improving distribution network reliability are captured. In order to obtain a bigger picture of the improvements brought about in the overall system reliability due to the injection of excess energy into the external grid by the VPP, generation and bulk power system based adequacy assessment methodologies are presented in this thesis. This strategy also facilitates the modelling of the market participation of VPPs by formulating an aggregated DER local network profile along with associated marginal costs defined at the transmission bus level, which is then presented to the independent system operator (ISO) similar to supply offer submissions from other grid-connected generators [7, 22].

A critical look at references [12–21] suggests one additional deficiency – they mostly make use of the ‘continuity criterion’ employed in distribution network reliability analyses which assumes that all local loads are met as long as they are connected to the external grid and there is sufficient power available, i.e., network constraints on the distribution side are usually ignored [23]. Since the DERs constituting the VPP are connected at different points across the distribution network, any equivalent

model representing the VPP must incorporate an aggregated portrayal of the various operating characteristics as well as capacities of the individual DERs and local loads, and must also contain relevant information about corresponding network characteristics, e.g., topology and constraints [7]. For this reason, linearized network flow based optimization formulations have been implemented in this thesis for incorporating relevant distribution network information into the overall VPP characterization procedure.

Finally, the distribution network cost/worth analyses presented in [20] and [21] model the external grid as a single entity characterized by a Thevenin equivalent source impedance. These references do not consider a holistic planning approach for determining an optimal DER portfolio for the VPP, so as to minimize its total operating, investment and interruption costs while carrying out transmission network contingency analysis using an explicit market clearing mechanism. This thesis addresses the limitations discussed above by proposing generic methodologies for performing generation and bulk power system adequacy and cost/worth assessments incorporating VPPs.

1.3. Research Contributions

Based on the discussions in Section 1.2, the major contributions made in this thesis are summarized in the following sub-sections. The overall methodologies proposed in this thesis are tested using the Roy Billinton Test System (RBTS) [24] as well as the IEEE Reliability Test System (RTS) [25]. Two distribution network test beds are separately used for modelling the VPP: the RBTS Bus 4 distribution network [26] and the (larger) IEEE 69-bus distribution network [27]. Monte Carlo sequential simulation techniques have been used for performing the studies as part of this research work.

1.3.1. Generation Adequacy Assessment Incorporating VPPs

A comprehensive Monte Carlo sequential simulation based generation adequacy assessment methodology incorporating an aggregated probabilistic model of a VPP is developed [29–30]. The disparate operating characteristics as well as capacities of individual DGs and local loads along with information about distribution network features like topology and constraints are combined together to form an equivalent model of a VPP using a linearized network flow based optimization formulation. The VPP is mathematically represented as a single entity with respect to the transmission grid, and its ‘prosumer’ (producer/consumer) characteristics are portrayed using a probability density function (PDF). The equivalent VPP model is used in conjunction with several new indices introduced – Mean VPP Export (MVPPE), Expected Renewable Energy Not Used (ERENU), Expected System Generation Supplemented (ESGS) and Expected System Generation Displaced (ESGD) – for quantifying different aspects of the VPP’s performance. Impacts of changes in the total installed VPP generation capacity as

well as the internal composition of the VPP's DG mix on the VPP performance and system adequacy indices are investigated.

1.3.2. Generation Adequacy Assessment Using Augmented VPP Model Incorporating ESDs

A general methodology is developed for investigating the impacts of incorporating ESDs into a VPP model and subsequently using it for performing generation adequacy studies [31]. A linear programming based multi-stage optimization formulation is proposed for combining the stochastic hourly-output based models of several DGs, ESDs and loads along with distribution network features like topology and constraints into an aggregated probabilistic representation of the VPP. Several modes pertaining to the charging/discharging of the distributed ESDs are integrated with the formulation using a fair energy allocation based operating strategy. The VPP indices (MVPPE, ERENU, ESGS and ESGD) introduced above are suitably modified for quantifying the impacts of the ESDs' incorporation on the performance of the VPP model. Sensitivity studies are carried out for analysing the impacts of variations in the ESD rated capacities, the ESD charging/discharging periods as well as the load forecast uncertainty on the VPP performance and system adequacy indices.

1.3.3. Bulk Power System Adequacy Assessment Incorporating VPPs

A systematic procedure is developed [32] for assessing bulk power system adequacy incorporating the equivalent VPP model presented in [31]. A linearized DC load flow based optimal power flow (OPF) formulation is proposed for performing transmission network contingency analysis. The OPF problem minimizes the total load curtailment and generation costs for the system, while also enabling priority dispatch of the VPP output (if available) into the external grid. The VPP performance indices (MVPPE, ERENU, ESGS and ESGD) are suitably modified for highlighting the impacts of transmission grid constraints and contingencies on the VPP profile characteristics. Key reliability indices computed at the system as well as at individual transmission bus levels are presented, with the VPP assumed to be connected at different transmission buses. Impacts of changes in factors such as the VPP's point of connection to the transmission grid as well as the failure and repair rates of transmission lines on the VPP's performance metrics are also studied.

1.3.4. Optimal VPP Planning from a Composite System Cost/Worth Perspective

The DC load flow based OPF formulation [32] is combined with composite system cost/worth analysis techniques for determining an optimal DER portfolio for the VPP so as to minimize the total perceived costs pertaining to the VPP's participation in day-ahead electricity markets. The costs associated with the VPP are sub-divided into five categories – energy import, customer interruption,

operation, investment and revenues – and different compositions and sizes of the DER mix are examined to determine the optimal portfolio which offers the highest cost savings for the VPP aggregator. The simulations are repeated with the VPP assumed to be connected at different transmission buses to highlight the impacts of transmission grid constraints and contingencies as well as the load curtailment priority and customer interruption costs associated with individual buses on the composition of the optimal DER portfolio along with the quantum of cost savings obtained.

1.4. General Structure of Thesis

The remaining chapters of this thesis are organized as follows. Chapter 2 presents an overview of the different methodologies available for performing adequacy assessment of power systems along with the various functional zones and hierarchical levels at which system adequacy can be assessed [28]. The chapter lists the key indices used to quantify system reliability at hierarchical levels I and II [33]. A brief literature review of available wind speed and solar irradiance forecasting techniques along with the autoregressive moving average (ARMA) models developed as part of this thesis for predicting hourly wind speed and solar irradiance values is also presented in Chapter 2. Detailed discussions on the methodologies adopted, formulations proposed and results obtained pertaining to the contributions described in Sections 1.3.1 – 1.3.4 are respectively presented in Chapters 3 through 6. Finally, Chapter 7 concludes the thesis with a summary of the work performed along with future research directions. The workflow involved in the execution of this PhD research work is graphically portrayed in Fig. 1.1.

Fig. 1.1 PhD research workflow

CHAPTER 2

GENERAL BACKGROUND

This chapter presents an overview of the different methodologies available for performing adequacy assessment of power systems along with the various functional zones and hierarchical levels at which system adequacy can be assessed. It lists the key indices used to quantify system reliability at hierarchical levels I and II. The chapter also presents a brief literature review of available wind speed and solar irradiance forecasting techniques along with the ARMA models developed as part of this thesis for predicting hourly wind speed and solar irradiance values.

2.1. Overview of Power System Reliability Evaluation Methodologies

The different techniques used for performing adequacy assessment of power systems can be grouped under one of three ‘hierarchical levels’ depending on the particular system segment or group of segments being analysed [33]. The three power system segments or ‘functional zones’ correspond to the generation, transmission and distribution networks, which in turn can be combined to yield the three hierarchical levels of power system reliability evaluation as shown below in Fig. 2.1 [33].

Fig. 2.1 Hierarchical levels of power system reliability evaluation

As can be seen from Fig. 2.1, adequacy assessments performed at the HLI stage (generation adequacy) model only the stochastic operating characteristics of generating units. HLII adequacy (bulk

power system adequacy) models the failures of both generating units and transmission lines while evaluating individual bus and overall system level reliability indices. Finally, an integrated adequacy assessment involving all three functional zones of the power system is carried out at the HLIII stage in order to compute customer load point reliability indices. Since generation and bulk power system adequacy assessments have been performed as part of this thesis, these are discussed in greater detail in the subsequent subsections.

Regardless of the hierarchical level at which an adequacy study is performed, power system reliability evaluation methodologies can be broadly classified under two categories – analytical and simulation [33]. For the benefit of the readers’ understanding, the classifications are graphically portrayed in Fig. 2.2.

Fig. 2.2 Classification of power system reliability evaluation methodologies

The analytical approach involves formulating a mathematical model for the system under consideration and extracting the expected values of reliability indices from the model using direct numerical solutions [33]. Analytical methods can be further sub-divided into several techniques, e.g., Markov state space processes, network reduction and min-cut sets, depending on the particular approach taken for building the mathematical model for the system [34].

Monte Carlo simulation based methodologies, on the other hand, assess system adequacy by imitating the stochastic operating characteristics of individual components using the probability distribution functions of component states or state durations [34]. The reliability evaluation problem is formulated as a series of sampled component states which are then combined to yield the overall state of the system, and reliability indices are estimated from the samples drawn using statistical inference tools [33–34]. Simulation techniques can be further sub-divided into two categories – non-sequential (e.g. state

sampling) and sequential simulation – depending on the order in which individual component states are sampled [34].

Hybrids of available reliability evaluation methodologies, e.g. a combination of analytical and state sampling approaches [35] as well as pseudo-sequential Monte Carlo simulation techniques [36] are often used to accurately model the intermittencies of renewable sources as well as time-varying loads while maintaining high computational efficiency.

2.2. Overview of Generation Adequacy Assessment (HLI) with Associated Indices

As mentioned in Section 2.1, generation adequacy assessments aim to quantify the ability of the system to satisfy demand while considering the scheduled and unscheduled outages of generating units as well as possible shortages in the supply of the basic energy source (e.g., wind for WTGs) [34]. Transmission and distribution network failures are ignored while carrying out generation adequacy assessments. Some of the important indices which have been used in this thesis for quantifying system adequacy at HLI using sequential simulation techniques are described below [33].

The Loss of Load Frequency ‘LOLF’ (occurrences/year) denotes the expected number of times per year the system transits from a ‘success’ to a ‘failure’ state. The LOLF is expressed as follows:

$$LOLF = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} t_{ij} \right) / N_y \quad (2.1)$$

where ‘ t_{ij} ’ is a binary variable equal to 1 whenever the system transits from a ‘success’ state in hour ‘ $i-1$ ’ to a ‘failure’ state in hour ‘ i ’ of simulation year ‘ j ’, and is 0 otherwise, and the term ‘ N_y ’ represents the total number of simulation years the reliability evaluation algorithm needs to be run for, until convergence is achieved.

The Loss of Load Expectation ‘LOLE’ (hours/year) represents the expected number of hours per year the system generation is inadequate to satisfy demand. The LOLE is expressed as follows:

$$LOLE = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} m_{ij} \right) / N_y \quad (2.2)$$

where ‘ m_{ij} ’ is a binary variable equal to 1 for all hours ‘ i ’ of year ‘ j ’ when the total system generation is less than the total system demand, and is 0 otherwise.

The Loss of Energy Expectation ‘LOEE’ (MWh/year) denotes the expected amount of energy that is not met by the system generation per year.

$$LOEE = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} \{m_{ij} * (P_{D,ij} - P_{G,ij})\} \right) / N_y \quad (2.3)$$

where ' $P_{G,ij}$ ' and ' $P_{D,ij}$ ' (both in MW) refer to the total system generation and total system demand respectively.

2.3. Overview of Bulk Power System Adequacy Assessment (HLII) with Associated Indices

The primary objective of carrying out bulk power system adequacy assessment is to model the effects of failures of generating units and transmission lines on the overall ability of the system to satisfy demand at the different load buses [33–34]. Due to the incorporation of transmission grid failures into the reliability evaluation procedure, HLII adequacy assessments essentially need to perform some form of transmission network contingency analysis using OPF formulations which may be based on linearized or non-linear load flow models depending on the target of the optimization as well as constraints considered [28]. For this reason, HLII studies are more complicated as well as more time-consuming as compared to their HLI counterparts.

The HLII adequacy assessment indices presented in this thesis have the same basic interpretations as those described in (2.1) – (2.3), but can be computed for individual transmission buses as well as for the overall system using the bus load curtailments output by the contingency analysis algorithm. Additionally, these HLII reliability indices are specified using different names as compared to their HLI counterparts. While LOLF is replaced by the Expected Frequency of Load Curtailments 'EFLC' (occurrences/year), LOLE is substituted by the Expected Duration of Load Curtailments 'EDLC' (hours/year), and the term Expected Energy Not Supplied 'EENS' (MWh/year) is used in place of LOEE [33].

2.4. Review of Wind Speed Prediction Tools

Input data requirements for performing power system adequacy and cost/worth assessments as part of this thesis using sequential simulation techniques are the predicted hourly wind speed and solar irradiance values. This section provides a brief review of the different wind speed prediction tools available [37–40]. References [39] and [40] review the most important forecasting models used for predicting hourly wind speed values: physical models (e.g., numerical weather prediction tools), conventional statistical models (e.g., ARMA, moving average (MA), etc.), spatial correlation models as well as artificial intelligence based new models (e.g., fuzzy logic, support vector machines, etc.). The best forecasting model to be used for a given simulation depends on several factors like the level of accuracy desired, the geographical area considered, the prediction time scale used, etc. [39].

Reference [41] provides an overview of the different methods for modelling and predicting hourly wind speeds while performing power system reliability evaluation studies. Some of the methods considered in [41] are Observed Wind Speeds, Mean Observed Wind Speeds, ARMA, MA, Normal

Distribution as well as Markov Chain model. A detailed methodology for predicting hourly wind speeds using an ARMA model is presented in [42]. The paper describes the important stages involved in the building of the model: parameter estimation, order determination as well as diagnostic checking. Reference [42] proposes two different wind speed prediction models based on ARMA, and after diagnostic checking and comparison of results, recommend the former as it is better capable of preserving the statistical characteristics of the observed wind speed data. One of the major disadvantages of predicting wind speeds using ARMA is the requirement of a huge database of historical values from which the required statistical information can be extracted in order to build a suitably accurate model. There are, however, many wind farm sites in the world which do not have any significant historical record of wind speed data. Reference [43] proposes a methodology for the development of a common wind speed model for such sites using the probability distribution functions of wind speeds from known locations. Once constructed, the common wind speed model can be used to determine the wind speed probability distribution for any geographical location, with the only data requirement being that of the annual mean wind speed and standard deviation for the concerned site [43].

2.5. Development of ARMA Model for Predicting Wind Speeds

The different methodologies available for generating synthetic sets of wind speed values are described in Section 2.4. The approach proposed in [42] has been used in this thesis for developing a suitable ARMA model which can in turn be used for predicting hourly wind speed values. Ten years (2002-2011) of hourly wind speed data was accessed from the National Renewable Energy Laboratory website [44] for estimating the parameters associated with the ARMA model. The observed data are from the South-Indian coastal city of Kanyakumari, which is situated at 8.08°N and 77.54°E. The normalized wind speed ' y_i ' for hour ' i ' is obtained as follows [42]:

$$y_i = (OW_i - \mu_i) / \sigma_i \quad (2.4)$$

where ' OW_i ', ' μ_i ' and ' σ_i ' respectively denote the observed wind speed, the mean observed wind speed and the standard deviation of the observed wind speed for hour ' i '.

Four years (2008-2011) of normalized hourly wind speed data was generated using (2.4), and this was used to estimate the parameters of several ARMA models of different orders using MATLAB in-built functions [45–46]. The F-criterion test described in [42] was employed to pick the most optimal ARMA model which provided the best fit for the observed wind speed time series data. The optimal ARMA(5,4) model which is used for predicting hourly wind speed values as part of this thesis is as follows:

$$y_i = 1.30662y_{i-1} + 0.275264y_{i-2} - 0.445001y_{i-3} - 0.503369y_{i-4} + 0.363053y_{i-5} + \alpha_i + 0.823475\alpha_{i-1} - 0.17799\alpha_{i-2} - 0.705941\alpha_{i-3} - 0.299087\alpha_{i-4} \quad (2.5)$$

where ' α_i ' denotes a normal white noise parameter with zero mean and a variance equal to 0.00497846. The ' y_i ' formulation presented in (2.5) can be used to produce a synthetic time series of normalized hourly wind speed data which can then be rescaled back to the corresponding simulated hourly wind speed values using (2.6) [42]:

$$SW_i = \mu_i + \sigma_i * y_i \quad (2.6)$$

where ' SW_i ' represents the simulated wind speed (meters/second) for hour ' i '. It may be noted that the ARMA model presented in (2.5) can generate either positive or negative normalized wind speed values owing to the fact that it is merely a mathematical representation which does not recognize wind speed as a real-world parameter. This in turn can lead to the generation of some negative simulated hourly wind speed values using (2.6). Several methods are presented in [37] for dealing with such negative values, but for the purpose of this thesis, all negative wind speeds thereby generated are set equal to their absolute values before being used in the adequacy assessment algorithms.

Several diagnostic checks recommended in [42] were performed using the observed and simulated hourly wind speed data in order to validate the adequacy of the ARMA model presented in (2.5), and some key results obtained are discussed as follows. Simulated hourly wind speed values were generated over a long time span of around 5000 years using (2.5) and (2.6), and key statistical parameters like mean and standard deviation were extracted from the synthesized time series. These were then compared with the corresponding values obtained from the observed wind speed data and the results are shown in Table 2.1.

TABLE 2.1
COMPARISON OF STATISTICAL PROPERTIES OF OBSERVED VS. SIMULATED WIND SPEED TIME SERIES

	Observed	Simulated
Mean (m/s)	4.4653	4.4781
Standard Deviation (m/s)	1.7052	1.7446

Table 2.1 suggests that the ARMA model presented in (2.5) is successful in generating synthetic hourly wind speed values which, over a long time span, have similar statistical properties as those characterizing the observed wind speed time series. This is also corroborated by Fig. 2.3 which shows how well the PDFs corresponding to the observed and simulated wind speed time series compare with each other.

Fig.2.3 Comparison of observed vs. simulated wind speed PDFs

Once the simulated wind speed for hour ‘i’ is obtained, the corresponding power output from a wind turbine generator (WTG) with rated capacity ‘ P_r ’ (MW) can be calculated using [47]:

$$P_{w,i} = \begin{cases} 0, & SW_i < V_{ci}, \text{ or } SW_i \geq V_{co} \\ (A + B * SW_i + C * SW_i^2) * P_r, & V_{ci} \leq SW_i < V_r \\ P_r, & V_r \leq SW_i < V_{co} \end{cases} \quad (2.7)$$

where ‘ $P_{w,i}$ ’ denotes the WTG power output (MW) for hour ‘i’; the constants ‘ V_{ci} ’, ‘ V_r ’ and ‘ V_{co} ’ respectively represent the cut-in, rated and cut-out wind speeds (meters/second) characterizing the particular WTG under consideration, and the A, B and C parameters are functions of ‘ V_{ci} ’, ‘ V_r ’ and ‘ V_{co} ’ and are calculated using the formulations presented in [47].

2.6. Review of Solar Irradiance Prediction Tools

This section provides a brief review of the different solar irradiance prediction tools available [48–50]. Though solar power shares the same properties of variability and intermittency as other renewable energy sources like wind, its seasonal and diurnal variations are more pronounced than in the case of wind as the intensity of solar irradiance at a given site is a function of its geographical coordinates, time of the day, season of the year, etc. While the extra-terrestrial irradiance measured

outside the earth's atmosphere can be measured accurately for any hour of the day and for any location, the randomness in the solar irradiance component measured on the earth's surface is introduced by the weather conditions (e.g., cloud cover) prevalent in the earth's atmosphere [51]. This randomness is quantified using the atmospheric transmittance variable, which is also known as the clearness index and is defined as the ratio of the solar irradiance measured on the earth's surface to that measured outside the earth's atmosphere [51–52]. Consequently, while some authors use the clearness index as the random variable in the statistical procedure used for predicting solar irradiance values [51–53], others directly use the observed solar irradiance time series for predicting future values [54–55]. Finally, there are a few publications which define an 'amended clearness index' as the ratio of the solar irradiance measured on the earth's surface to the clear sky radiation value and use this as the random variable in their prediction algorithm [48, 56].

An innovative methodology based on higher order statistics for random processes is presented in [52] for predicting daily solar irradiance values. Two simulations are run using the proposed prediction algorithm with two different parameters being used as random variables for the respective runs: the daily clearness index as well as the 'lost solar component'. The daily solar irradiance values generated from the two simulation runs are then compared, and it is concluded that the predictions made by the latter model are more accurate than those made by the former [52]. An ARMA based methodology for predicting hourly irradiance values is presented in [55], wherein the authors decompose the hourly irradiance measurements into two parts: a deterministic as well as a stochastic component. While the stochastic part is modelled using ARMA techniques, the deterministic component is computed by taking a grand average of the known irradiance sequence over the entire observation period [55]. Reference [57] proposes a methodology for predicting the daily sequence of irradiance values for sites lacking significant historical irradiance records, with the only input required being the average monthly irradiance values for the concerned location. The proposed methodology incorporates a library of Markov Transition Matrices, each corresponding to a given range of the monthly average clearness index ' $\overline{K_t}$ ' at the given location [57]. Reference [58] uses MATLAB in-built functions for predicting hourly solar irradiance values using two different techniques: ARMA and persistence models. The forecasting errors associated with the two techniques are analysed and it is concluded that while the ARMA model is good at predicting irradiance values over a short to medium time frame, the persistence model is useful only for making very short term predictions [58]. A Time-dependent Autoregressive Gaussian model is introduced in [59] for predicting hourly solar irradiance values on a horizontal plane on the earth's surface using the daily clearness index ' K_t ' as well as different solar hours at the given location as inputs.

2.7. Development of ARMA Model for Predicting Solar Irradiance

Section 2.6 provides an overview of the different techniques available for generating synthetic sets of solar irradiance values. An ARMA based approach has been adopted in this thesis for predicting hourly solar irradiance values using the methodologies described in [48] and [55].

For estimating the parameters associated with the ARMA model, the same ten years (2002-2011) of hourly solar irradiance data observed at the Indian city of Kanyakumari was accessed from the National Renewable Energy Laboratory website [44]. Several ARMA models of different orders were built using MATLAB in-built functions [45–46], and the F-criterion test described in [42] was used to select the most optimal amongst them. The resultant ARMA(2,1) model which is used for predicting hourly solar irradiance values as part of this thesis is as follows:

$$y_i = 0.879506y_{i-1} - 0.0630914y_{i-2} + \alpha_i - 0.34302\alpha_{i-1} \quad (2.8)$$

where ‘ α_i ’ denotes a normal white noise parameter with zero mean and a variance equal to 0.26019. Key results obtained from the diagnostic checks conducted using the observed and simulated hourly irradiance data are presented below.

Simulated hourly solar irradiance values (kW/m²) were generated over a long time span of around 5000 years using the ARMA model of (2.8), and key statistical parameters like mean and standard deviation were extracted from the synthesized time series. These were then compared with the corresponding values obtained from the observed irradiance data and the results are shown in Table 2.2.

TABLE 2.2
COMPARISON OF STATISTICAL PROPERTIES OF OBSERVED VS. SIMULATED SOLAR IRRADIANCE TIME SERIES

	Observed	Simulated
Mean (kW/m ²)	0.24589398	0.24865441
Standard Deviation (kW/m ²)	0.3292	0.32395272

The PDFs corresponding to the observed and simulated irradiance series were plotted for a typical winter month of January and a typical summer month of July, and the results of the comparison are depicted in Figs. 2.4 and 2.5 respectively. For the benefit of the readers’ understanding, zoomed-in versions of the PDFs of Figs. 2.4 and 2.5 in the vicinity of the origin are also presented as insets in the respective figures.

Once the simulated solar irradiance for hour ‘i’ is determined, the corresponding power output from a PV system comprising ‘N’ PV modules can be calculated using [60]:

Fig. 2.4 Comparison of observed vs. simulated solar irradiance PDFs for January

Fig. 2.5 Comparison of observed vs. simulated solar irradiance PDFs for July

$$P_{s,i} = N * FF * V_{y,i} * I_{y,i} \quad (2.9)$$

$$FF = (V_{MPP} * I_{MPP}) / (V_{oc} * I_{sc}) \quad (2.10)$$

$$T_{c,i} = T_{a,i} + SSR_i * (NOCT - 20) / 0.8 \quad (2.11)$$

$$V_{y,i} = V_{oc} - k_v * T_{c,i} \quad (2.12)$$

$$I_{y,i} = SSR_i * \{I_{sc} + k_i * (T_{c,i} - 25)\} \quad (2.13)$$

where ‘ $P_{s,i}$ ’ and ‘ FF ’ respectively denote the total PV power output (MW) for hour ‘ i ’ and the fill factor of the PV modules; the parameters ‘ V_{MPP} ’, ‘ V_{oc} ’, ‘ I_{MPP} ’, ‘ I_{sc} ’, ‘ $NOCT$ ’, ‘ k_v ’ and ‘ k_i ’ respectively represent the maximum power point and open circuit voltages (V), the maximum power point and short circuit currents (A), the nominal operating cell temperature (°C) and the voltage (V/°C) and current (A/°C) temperature coefficients characterizing the particular PV module under consideration, and the variables ‘ $T_{c,i}$ ’, ‘ $T_{a,i}$ ’ and ‘ SSR_i ’ respectively stand for the cell and ambient temperatures (°C) and the simulated solar irradiance (kW/m²) for hour ‘ i ’. As expressed in (2.10), the fill factor is the ratio of the maximum obtainable power from the PV module (corresponding to the maximum power point) to the theoretical maximum [14].

2.8. Summary

This chapter provides a general background of the basic principles based on which this research work has been conducted. The power system adequacy assessment methodologies along with associated indices used throughout this report have been introduced. ARMA models developed for generating hourly wind speed and solar irradiance values to be used in the sequential algorithms employed throughout this research work have also been presented.

CHAPTER 3

GENERATION ADEQUACY ASSESSMENT INCORPORATING VPPs

This chapter presents a generic methodology for assessing the generation adequacy of power systems incorporating an aggregated probabilistic model representing several smart distribution network components and features in the form of a VPP. Randomly varying hourly outputs of individual components like DGs and loads are combined with information about important distribution network features like topology and constraints to form the aggregated probabilistic model of the VPP using a proposed linearized network flow based optimization formulation. The proposed formulation therefore facilitates the VPP's modelling as a single equivalent unit with respect to the transmission grid. This equivalent model is used together with new indices introduced for quantifying different aspects of the VPP's performance. The chapter also investigates the impacts of changes in the total installed VPP generation capacity as well as the internal composition of the VPP's DG mix on the VPP performance and system reliability indices. The overall proposed methodology is implemented on the RBTS [24] as well as the IEEE RTS [25]. Two distribution network test beds are separately used for modelling the VPP: the RBTS Bus 4 distribution network [26] and the (larger) IEEE 69-bus distribution network [27]. Monte Carlo sequential simulation techniques are used for performing the simulations, and results obtained are discussed in detail.

3.1. Introduction

3.1.1. Literature Review

Several publications [13, 15, 18–19, 35, 61–62] present an aggregated treatment of smart distribution network components like DERs and loads as part of their proposed power system adequacy assessment procedures. An analytical formulation for computing distribution network reliability indices is proposed in [13], after incorporating DERs and protection equipment in the concerned network. Reference [15] presents a state sampling based approach for performing reliability assessment of active distribution systems incorporating micro-grids, wherein the latter's constituent DERs and loads are modelled together as a VPP characterized by a 'generalized capacity outage table' with discrete 'source' and 'customer' states of operation. References [18] and [19] present detailed network aggregation techniques for representing low and medium voltage distribution networks using their reliability equivalent models, which are in turn incorporated into the overall proposed sequential simulation methodology for assessing the adequacy of distribution networks. An operating reliability analysis framework incorporating VPPs bidding in energy and ancillary services markets is presented in [61],

wherein the VPP is modelled as an equivalent entity featuring the aggregated characteristics of its constituent DERs. References [35] and [62] use a combination of basic reliability evaluation techniques (e.g., a hybrid of the analytical and state sampling approaches) for performing adequacy assessment of smart distribution networks while ensuring faster algorithm convergence.

3.1.2. Motivations

The system adequacy studies presented in the literature reviewed in Section 3.1.1 are all carried out at the distribution network level. Considering the example of the VPP modelled in [15], it is clear that these distribution network reliability evaluations are unable to quantify the VPP's average annual energy exports to the transmission grid after satisfying internal network demands and constraints, which in turn can provide a more holistic picture of the VPP's revenue generation potentials from participation in electricity and ancillary services markets. Reference [61] does model the VPP's participation in these markets as an aggregated entity, however, the VPP's energy contributions are limited only to satisfying its own internal network demands. Additionally, the reviewed literature fails to quantify the VPP's contributions in improving overall system adequacy at HLI. Another deficiency in most of the reviewed literature is that they fail to incorporate information about important distribution network features like topology and constraints into the overall model of the VPP profile. Since the VPP's constituent DERs are distributed across its internal nodes, ignoring the effects of network features during the VPP's modelling may result in an overly optimistic characterization of its profile. The work presented in this chapter addresses the limitations in the reviewed literature by introducing a comprehensive Monte Carlo sequential simulation based generation adequacy assessment methodology incorporating an aggregated probabilistic model of a VPP [29–30].

3.1.3. Contributions

The principal contributions of this chapter are as follows: 1) The disparate operating characteristics as well as capacities of individual DGs and local loads along with information about distribution network features like topology and constraints are combined together to form an equivalent model of a VPP using a linearized network flow based optimization formulation. The VPP is mathematically represented as a single entity with respect to the transmission grid, and its 'prosumer' (producer/consumer) characteristics are portrayed using a PDF. 2) The equivalent VPP model is used in conjunction with several new indices introduced in this chapter – MVPPE, ERENU, ESGS and ESGD – for quantifying different aspects of the VPP's performance. 3) Impacts of changes in the total installed VPP generation capacity as well as the internal composition of the VPP's DG mix on the VPP performance and system reliability indices are investigated.

3.2. Layout of Distribution Network Components Being Modelled in VPP

Two sets of simulation runs were conducted for testing the overall methodology proposed in this chapter. The first set of simulations was run using the RBTS, which is a 6-bus system with 9 transmission lines, 11 generating units, and a total installed capacity of 240 MW and a system peak load of 185 MW [24]. Relevant details of the RBTS are presented in Appendix A. The RBTS Bus 4 distribution network [26] consisting of 7 feeders and 38 load points is used for modelling the VPP as part of the first set of simulation runs performed, after augmenting the network by introducing several DGs connected across its internal nodes as shown in Fig. 3.1. The VPP is characterized by an annual peak load of 40 MW, with its internal network assumed to be located at Bus 4 of the RBTS as indicated in Fig. 3.1. The DER portfolio portrayed in Fig. 3.1 is assumed to be composed of three PV systems each at nodes 8 and 19, two gas turbines each at nodes 12 and 15 and three WTGs each at nodes 24 and 32 of the RBTS Bus 4 distribution network. Note that the sub-transmission network connecting the 230 kV RBTS transmission grid with the 11 kV distribution network, as well as the demands associated with individual nodes of the RBTS Bus 4 distribution network are not explicitly shown in Fig. 3.1 for the sake of simplicity.

Fig. 3.1 Schematic representation of RBTS Bus 4 distribution network showing locations of DGs and loads

The second set of simulations was similarly run using the IEEE RTS, which is a 24-bus system with 38 transmission lines, 32 generating units, and a total installed capacity of 3405 MW and a system peak load of 2850 MW [25]. Relevant details of the RTS are presented in Appendix B. The IEEE 69-bus distribution network [27] consisting of 8 feeders and 69 load points is used for modelling the VPP as part of the second set of simulation runs performed, after augmenting the network by introducing several DGs connected across its internal nodes as shown in Fig. 3.2. The VPP is characterized by an annual peak load of 181 MW, with its internal network assumed to be located at Bus 19 of the RTS as indicated in Fig. 3.2. The DER portfolio portrayed in Fig. 3.2 is assumed to be composed of two WTGs at node 29, a WTG at node 66, four WTGs at node 12, three WTGs at node 47, a PV generator at node 33, three PV generators at node 39, two PV generators each at nodes 43, 44 and 63, and three gas turbines each at nodes 38 and 50.

Fig. 3.2 Schematic representation of IEEE 69-bus distribution network showing locations of DGs and loads

3.3. Proposed Generation Adequacy Assessment Methodology

3.3.1. Modelling of Distributed Generators

The ARMA models presented in Sections 2.5 and 2.7 are respectively used for generating synthetic sequences of hourly wind speed and solar irradiance values required for computing the corresponding power outputs from the VPP's constituent WTGs and PV systems. Two uncertainties have been considered in this research work while modelling the hourly power outputs from renewable distributed generators (DG): random failures (unplanned outages) as well as the intermittencies associated with the supply of the DGs' basic energy sources, e.g., wind. While the former is realized through random DER state transitions modelled using the sequential algorithm of Section 3.3.6, the latter is simulated using the ARMA models from Sections 2.5 and 2.7.

Brief reviews of available wind speed and solar irradiance prediction tools are presented in Sections 2.4 and 2.6 respectively. However, keeping in mind the main focus of this chapter on devising a generic methodology for performing generation adequacy assessment incorporating the equivalent model of the VPP, ARMA models have been used as just one of several techniques available for predicting the hourly wind speed and solar irradiance values. The ARMA models can be easily substituted by an alternative forecasting tool (e.g., ARIMA, artificial neural networks, etc.) as per the requirements of a given study.

The sole uncertainty considered while modelling the hourly power outputs from conventional DGs is the random failures (unplanned outages) associated with their operations. Consequently, the power outputs of these DGs can randomly assume one of many possible discrete values (between zero and rated power) depending on the total number of states considered in the concerned DG's failure model. Random failures in the conventional DGs are simulated through chronological component state transitions modelled using the sequential algorithm of Section 3.3.6.

3.3.2. Modelling of Distribution Network Load Profile

The IEEE RTS randomly varying hourly load model [25] is used for performing the simulations reported in this thesis. Relevant details of this load model are presented in Appendix C. The hourly demands at any given node 'n' of the distribution network test bed under consideration are assumed to vary in the same proportion as the overall system load.

3.3.3. Development of Equivalent VPP Model Using Proposed Optimization Formulation

Equations (3.1) – (3.5) present the linearized network flow based optimization formulation for developing the equivalent model of the VPP by combining the randomly varying hourly outputs of its

associated DGs and loads together with information about important distribution network characteristics like topology and line flow constraints.

Objective function:

$$\min \{ (w^r * \sum C_{k,ij}^r) + (w^c * \sum C_{k,ij}^c) \}, \forall k \in K \quad (3.1)$$

Constraints:

$$\sum P_{l,n,ij}^{in} + \sum G_{k,n,ij} = D_{n,ij} + \sum P_{l,n,ij}^{out}, \forall n \in N \quad (3.2)$$

$$G_{k,min} \leq G_{k,ij} \leq G_{k,max,ij}, \forall k \in K \quad (3.3)$$

$$G_{k,ij} = G_{k,max,ij} - C_{k,ij}, \forall k \in K \quad (3.4)$$

$$abs(P_{l,ij}) \leq P_{l,max}, \forall l \in L \quad (3.5)$$

where ‘N’, ‘K’ and ‘L’ respectively denote the set of all nodes, DGs and lines belonging to the distribution network test bed under consideration; ‘ $\sum C_{k,ij}^r$ ’ and ‘ $\sum C_{k,ij}^c$ ’ (both in MW) respectively represent the total generation curtailments that might need to be carried out from the VPP’s constituent renewable and conventional source based DGs for satisfying line flow constraints in the VPP’s internal distribution network; ‘ w^r ’ and ‘ w^c ’ respectively denote the weights assigned to the renewable and conventional generation curtailments; ‘ $\sum P_{l,n,ij}^{in}$ ’, ‘ $\sum P_{l,n,ij}^{out}$ ’, ‘ $\sum G_{k,n,ij}$ ’ and ‘ $D_{n,ij}$ ’ (all in MW) respectively represent the total incoming and outgoing line flows, the total DG power outputs and the demand associated with a given node ‘n’ of the distribution network test bed under consideration; ‘ $G_{k,ij}$ ’, ‘ $C_{k,ij}$ ’ and ‘ $P_{l,ij}$ ’ (all in MW) represent the actual power dispatch along with the associated generation curtailment from DG ‘k’ and the power flow in line ‘l’ respectively; ‘ $G_{k,min}$ ’ and ‘ $P_{l,max}$ ’ (both in MW) respectively denote the minimum output associated with DG ‘k’ and the maximum power rating of line ‘l’; ‘ $G_{k,max,ij}$ ’ (MW) denotes the maximum power that can be obtained from DG ‘k’ after taking into consideration its failure state as well as the possible uncertainty in supply of its basic energy source; and ‘i’ and ‘j’ respectively denote a particular hour of a given simulation year of the sequential algorithm used in this research work. The convention used for defining the incoming ($P_{1,ij}$, $P_{2,ij}$ and $P_{5,ij}$) and outgoing ($P_{VPP,ij}$) line flows with respect to the sample node 0 of the RBTS Bus 4 distribution network is depicted in Fig. 3.1.

The objective function (3.1) ensures that maximum possible curtailments (i.e., if curtailments are necessary) are carried out from the conventional DGs before reducing the dispatch from the renewable generators. This is implemented by assigning a higher weight ‘ w^r ’ (i.e., higher penalty) to the renewable generation curtailments ‘ $C_{k,ij}^r$ ’ as compared to that (w^c) assigned to the conventional generation curtailments ‘ $C_{k,ij}^c$ ’. Note that both ‘ w^r ’ and ‘ w^c ’ are positive quantities, and one needs to be only concerned about their relative (as opposed to individual) magnitudes while assigning corresponding

values in (3.1). While (3.2) enforces the conservation of power principle at each node ‘n’ of the distribution network test bed under consideration, (3.4) defines the curtailed generation from DG ‘k’ as the difference between its maximum obtainable and actual power dispatches. Constraints (3.3) and (3.5) respectively ensure that the power outputs from individual DGs as well as the line flows stay within appropriate limits.

The proposed formulation (3.1) – (3.5) is a linear programming problem, and its optimal solution is obtained using the ‘*linprog*’ function in-built in the MATLAB optimization toolbox [63]. For each hour ‘i’ of year ‘j’, the ‘*linprog*’ function therefore helps to output the optimal (minimum) generation curtailments ($\Sigma C_{k,ij}^r$ and $\Sigma C_{k,ij}^c$) that might need to be carried out from the VPP’s constituent DGs, which in turn ensures maximization of the energy that is injected by them. Since distribution losses are ignored as part of the network flow based formulation (3.1) – (3.5), its principal goal – maximization of the energy that the VPP can inject into the transmission grid after satisfying internal network demands and constraints – is therefore automatically achieved. Consequently, the *decision variable* ‘ $P_{VPP,ij}$ ’ is used for quantifying the principal goal of the formulation (3.1) – (3.5) as:

Decision variable:

$$P_{VPP,ij} = \sum_{\forall k \in K} G_{k,ij} - \sum_{\forall n \in N} D_{n,ij} \quad (3.6)$$

where ‘ $P_{VPP,ij}$ ’ (MW) represents the optimal (maximum) energy that the VPP can export to the transmission grid after satisfying internal network demands and constraints.

For each hour ‘i’ of year ‘j’, the solution of (3.1) – (3.6) therefore enables one to replace all available inputs ($G_{k,max,ij}$, $D_{n,ij}$, $G_{k,min}$ and $P_{l,max}$) with a single *equivalent* parameter ‘ $P_{VPP,ij}$ ’ representing the optimal VPP output computed at the transmission grid interface. If one is now able to extract the distribution associated with a long sequence of randomly varying hourly ‘ $P_{VPP,ij}$ ’ values generated by the sequential algorithm of Section 3.3.6, this distribution (portrayed through a PDF) will then define the equivalent model of the VPP as a single aggregated unit with respect to the transmission grid.

The proposed formulation (3.1) – (3.5) is generic in nature, and can easily handle any practical topology (e.g., radial and ring) as well as any given configuration of DGs in the VPP’s internal distribution network. Readers should note that even though more advanced DC and/or AC load flow based OPF formulations for distribution networks do exist in the literature [64], a network flow based optimization formulation was considered sufficient for the generation adequacy assessments (which model system generation and demand as lumped parameters while ignoring all line constraints, losses and topology related information [28]) described in this chapter.

3.3.4. Adopted VPP Operating Policy

The optimization formulation (3.1) – (3.5) is purely reflective of the generic VPP operating policy adopted for this chapter. It is firstly assumed that the distribution network operator (DNO) plays the role of the VPP aggregator, though this role can also be handled by other private players [7]. For each hour ‘i’ of year ‘j’, the DNO first obtains the optimal VPP output ‘ $P_{VPP,ij}$ ’ using (3.1) – (3.6). In case the VPP has excess energy to inject into the transmission grid after satisfying internal network demands and constraints (i.e., $P_{VPP,ij} > 0$), the same is dispatched by the ISO on a priority basis for meeting ‘external grid demand’ (total system demand minus the VPP’s total internal network demand). In case some external grid demand is still left unsatisfied after the dispatch of ‘ $P_{VPP,ij}$ ’, the ISO meets this deficit by dispatching ‘original system’ (the system before the VPP’s incorporation) generation according to a pre-specified loading order [24]. Alternatively, if the total generation dispatched from the VPP’s constituent DGs is less than its total internal network demand (i.e., $P_{VPP,ij} < 0$), the VPP appears as a consumer to the ISO, which in turn supplies its energy deficit by dispatching original system generation. Keeping in mind the main focus of this chapter on presenting a generation adequacy based study (which is a planning issue), an important thing to note is that electricity prices and market signals (which are mostly considered from an operational perspective) are not explicitly incorporated into the adopted VPP operating policy. The policy therefore implicitly assumes that the DNO is able to offer the excess energy ‘ $P_{VPP,ij}$ ’ either at a favourable price or in a favourable regulatory setting (perhaps with help from local authorities in the form of guaranteed feed-in tariffs and/or special market premiums as offered by some European Union countries [5, 7–8]), so as to enable the ISO to dispatch that energy on a priority basis for meeting external grid demand.

The rationale behind adopting this generic operating policy is basically to portray the VPP as an attractive business model to interested DG owners by giving them maximum opportunities to generate revenues from participation in electricity markets, which is in turn realized through the extraction of maximum possible energy from the VPP’s constituent DGs and using it to supply internal network and external grid demands. The adopted operating policy and the proposed optimization formulation also encourage the growth of renewable DGs in the VPP’s generation portfolio by carrying out maximum possible curtailments from the conventional generators before reducing the dispatch from the renewable source based units. One should, however, note that the adopted operating policy along with the formulation (3.1) – (3.5) are by no means the only ones – any suitable alternative can be easily considered in order to satisfy the specific targets of a given research project.

Finally, the hosting capacities associated with different distribution network feeders are dependent on a number of factors [65], e.g., the sizing and the siting of the DGs, relevant feeder constraints around the points of connection of the DGs, relative proximity between the DGs, investments

made for implementing distribution network control schemes for managing energy injections from the DGs, etc. With a steady rise in the number of DGs connected to distribution networks worldwide, it is therefore important to note that the ability to implement the proposed energy export based VPP operating policy will be limited at increased levels of DG penetrations beyond the applicable hosting capacity limits owing to increased occurrences of node voltage, line flow, protection equipment and stability margin related constraint violations in the distribution network test bed under consideration [65]. Many studies have in fact been conducted for quantifying the maximum permissible DG penetration in a given distribution network, while ensuring zero node voltage violations [66] as well as the minimization of network losses [67]. However, keeping in mind the main focus of this chapter on performing generation adequacy assessment incorporating the equivalent VPP model, the adopted operating policy implicitly assumes that the chosen DG penetration levels fall within applicable hosting capacity limits for the distribution network test bed under consideration, which in turn ensures that relevant node voltage, protection equipment and stability margin related constraints are satisfied. Such an assumption is routine and normally acceptable for system adequacy studies conducted at HLI for planning purposes [28].

3.3.5. VPP Performance Indices

Four new energy-based indices are introduced in this section for quantifying different aspects of the VPP's performance from its own as well as from the original system's perspective. All index formulations are based on the adopted VPP operating policy described in Section 3.3.4.

The index Mean VPP Export 'MVPPE' (MWh/year) quantifies the expected amount of energy that the VPP exports to the transmission grid in a year after satisfying internal network demands and constraints. MVPPE is formulated as:

$$MVPPE = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} \max(0, P_{VPP,ij}) \right) / N_y \quad (3.7)$$

where ' $P_{VPP,ij}$ ' is obtained using (3.1) – (3.6).

The index Expected Renewable Energy Not Used 'ERENU' (MWh/year) is used for quantifying the expected amount of energy from renewable source based DGs that needs to be curtailed every year due to the VPP's internal network constraints. ERENU is formulated as:

$$ERENU = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} \{ \sum C_{k,ij}^r \} \right) / N_y \quad (3.8)$$

where ' $\sum C_{k,ij}^r$ ' is obtained using (3.1) – (3.5).

The index Expected System Generation Displaced 'ESGD' (MWh/year) quantifies the expected demand per year that would have otherwise been met by the original system generation but is now

supplied by the VPP. The final index Expected System Generation Supplemented ‘ESGS’ (MWh/year) is used for computing the expected demand per year that would have otherwise remained unsatisfied due to deficiency in the original system generation but is now supplied by the VPP. ESGD and ESGS are formulated as follows:

If $P_{G,ij} \geq P_{D,ij}$:

$$ESGS_{ij} = 0 \quad (3.9)$$

$$ESGD_{ij} = \sum_{\forall k \in K} G_{k,ij} \quad (3.10)$$

elseif $P_{G,ij} < P_{D,ij}$ & $P_{G,ij} + \sum_{\forall k \in K} G_{k,ij} \geq P_{D,ij}$:

$$ESGS_{ij} = P_{D,ij} - P_{G,ij} \quad (3.11)$$

$$ESGD_{ij} = \sum_{\forall k \in K} G_{k,ij} - ESGS_{ij} \quad (3.12)$$

else $(P_{G,ij} + \sum_{\forall k \in K} G_{k,ij} < P_{D,ij})$:

$$ESGS_{ij} = \sum_{\forall k \in K} G_{k,ij} \quad (3.13)$$

$$ESGD_{ij} = 0 \quad (3.14)$$

$$ESGS = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} \{ESGS_{ij}\} \right) / N_y \quad (3.15)$$

$$ESGD = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} \{ESGD_{ij}\} \right) / N_y \quad (3.16)$$

where ‘ $P_{G,ij}$ ’ and ‘ $P_{D,ij}$ ’ (both in MW) refer to the total original system generation and total system demand respectively.

Note that while MVPPE and ERENU can serve as useful indicators to the DNO about the modelled VPP’s performance from its own perspective, ESGD and ESGS can provide system planners deep insights into the impacts of the VPP’s integration from the original system’s point of view.

3.3.6. Overall Sequential Simulation Algorithm

The Monte Carlo sequential simulation algorithm [28] used for implementing the overall methodology presented in this chapter is schematically represented in Fig. 3.3. Component failures are considered only for the original system generating units as well as individual DGs belonging to the distribution network test bed under consideration. All repairable components are represented by a two-state (Up/Down) model, although unit deratings as part of multistate component failure models can be easily incorporated into the overall sequential simulation procedure [28]. All repairable components are assumed to be in their ‘Up’ states at the start of the simulations. Note that the tasks contained within the red dotted rectangle in Fig. 3.3 depict the additional steps which need to be executed as part of the proposed sequential simulation algorithm in order to incorporate the equivalent VPP model into the overall generation adequacy assessment methodology presented in this chapter.

Fig. 3.3 Schematic representation of the proposed sequential simulation algorithm

3.4. Analysis of Results

3.4.1. Details of Simulation Setup

As mentioned in Section 3.2, two sets of simulation runs were conducted for testing the overall methodology proposed in this chapter: the first one corresponding to the RBTS coupled with its Bus 4 distribution network [24, 26], and the second set corresponding to the IEEE RTS in conjunction with the IEEE 69-bus distribution network [25, 27].

The first set of simulations was carried out corresponding to a total rated VPP generation capacity of 48 MW, which was assumed to be equally divided amongst its 16 DGs. The locations and types of these DGs are presented in Section 3.2 Fig. 3.1. Individual DGs for the first set of simulations are therefore assumed to have a rated output of 3 MW. The second set of simulations was carried out corresponding to a total rated VPP generation capacity of 156 MW, which was assumed to be equally

divided amongst its 26 DGs. The locations and types of these DGs are presented in Section 3.2 Fig. 3.2. Individual DGs for the second set of simulations are therefore assumed to have a rated output of 6 MW.

Failure and repair rates data for the VPP's constituent DGs along with the WTGs' characteristic cut-in, rated and cut-out wind speed values are taken from [29] for both sets of simulations. Values of characteristic parameters for PV modules are obtained from [60]. Remaining specifications regarding the load profile used for the simulations as well as the ARMA models used for predicting hourly wind speed and solar irradiance values are presented in Sections 3.3.2, 2.5 and 2.7 respectively.

3.4.2. Characterization of VPP profile

Fig. 3.4 PDF representing equivalent VPP model developed using augmented RBTS Bus 4 distribution network

The equivalent VPP model presented in Section 3.3.3 and developed using the augmented RBTS Bus 4 distribution network of Fig. 3.1 is represented by the PDF of Fig. 3.4. The PDF, which is a portrayal of the distribution associated with the decision variable ' $P_{VPP,ij}$ ', offers a single aggregated representation of the VPP's profile with respect to the transmission grid by combining the randomly varying hourly outputs of its constituent components like DGs and loads together with information about important distribution network characteristics like topology and constraints. The PDF therefore offers the impression of a single 'virtual power plant' to an observer on the transmission grid side. The dual modes ('Producer' or 'Consumer') the VPP can operate in as per the energy balance in its internal network are

demarcated using the $P_{VPP,ij} = 0$ line in Fig. 3.4. The area under the PDF to the right of the $P_{VPP,ij} = 0$ line gives the long term probability of the VPP operating in the ‘Producer’ mode exporting energy to the transmission grid, and is computed to be equal to 0.1884. The mean of the PDF of Fig. 3.4 is -6.457 MW, which implies that on an average, the VPP appears to the external grid as a consumer.

The VPP performance indices defined in Section 3.3.5 and computed using the RBTS along with its Bus 4 distribution network are listed in Table 3.1. Since the average annual energy supplied by all the VPP’s constituent DGs combined is equal to ESGD + ESGS, it can be observed from Table 3.1 that the MVPPE is only about 4.03% of this total sum. This in turn implies that (on an average) close to 96% of the modelled VPP’s total energy generation is used for satisfying its internal network demand. It can also be seen from Table 3.1 that the ESGS is almost negligible as compared to ESGD. This is owing to a strong reserve margin of 29.73% for the original RBTS, which ensures that $P_{G,ij} \geq P_{D,ij}$ for most hours ‘i’ simulated by the sequential algorithm of Section 3.3.6 (refer to (3.9) – (3.16) for details on ESGD and ESGS definitions). One final observation to be made from Table 3.1 pertains to the percentage contributions (as indicated by the numbers within the square brackets) of the renewable (WTGs + PV systems) and conventional (gas turbines) DGs to the final computed ESGD and ESGS values. In spite of the fact that the installed capacity of the gas turbines is only 25% of the total rated VPP generation capacity, they can be seen to be contributing more than 50% of the total energy production of the VPP, which basically highlights the impacts of the intermittencies associated with the renewable DG outputs.

TABLE 3.1
VPP PERFORMANCE INDICES COMPUTED FOR RBTS

<i>VPP performance indices</i>	
MVPPE (MWh/year)	6.4016×10^3
ERENU (MWh/year)	195.3857
ESGD (MWh/year)	1.5872×10^5
[WTG+PV/GT %]	[41.7/58.3]
ESGS (MWh/year)	8.653
[WTG+PV/GT %]	[43.3/56.7]

Similarly, the equivalent VPP model developed using the augmented IEEE 69-bus distribution network of Fig. 3.2 is represented by the PDF of Fig. 3.5. The area under the PDF to the right of the $P_{VPP,ij} = 0$ line gives the long term probability of the VPP operating in the ‘Producer’ mode exporting energy to the transmission grid, and is computed to be equal to 0.0193. The mean of the PDF of Fig. 3.5 is -54.3229 MW. The VPP performance indices computed using the RTS coupled with the IEEE 69-bus distribution network are listed in Table 3.2. The data in Tables 3.1 and 3.2 demonstrate how the VPP performance indices vary as a function of the sizing and siting of the DGs with respect to the topology and constraints of the VPP’s internal distribution network as well as the original system generation and load profile.

Fig. 3.5 PDF representing equivalent VPP model developed using augmented IEEE 69-bus distribution network

TABLE 3.2
VPP PERFORMANCE INDICES COMPUTED FOR IEEE RTS

<i>VPP performance indices</i>	
MVPPE (MWh/year)	1.4125×10^3
ERENU (MWh/year)	5.3408×10^2
ESGD (MWh/year)	4.9789×10^5
[WTG+PV/GT %]	[44.34/55.66]
ESGS (MWh/year)	4.7727×10^2
[WTG+PV/GT %]	[48.37/51.63]

3.4.3. Overall Generation Adequacy Assessment Results

Table 3.3 compares the key system reliability indices LOLF, LOLE and LOEE [33] computed from the generation adequacy assessment of the original RBTS with the corresponding values generated after incorporating the equivalent VPP model into the RBTS. Similarly, Table 3.4 compares the values of key system reliability indices as computed for the original IEEE RTS vis-à-vis those obtained after incorporating the equivalent VPP model into the RTS. These results quantify the overall reliability improvements brought about by the VPP's integration into the respective systems.

TABLE 3.3
COMPARISON OF KEY SYSTEM RELIABILITY INDICES COMPUTED FOR RBTS

<i>System reliability indices associated with →</i>	<i>Original RBTS</i>	<i>RBTS+VPP</i>
LOLF (occurrences/year)	0.2293	0.0488
LOLE (hours/year)	1.1542	0.1584
LOEE (MWh/year)	11.063	1.2710

TABLE 3.4
COMPARISON OF KEY SYSTEM RELIABILITY INDICES COMPUTED FOR RTS

<i>System reliability indices associated with →</i>	<i>Original RTS</i>	<i>RTS+VPP</i>
LOLF (occurrences/year)	1.9552	1.3783
LOLE (hours/year)	9.8727	6.1464
LOEE (MWh/year)	1.3016×10^3	7.4806×10^2

3.4.4. Impacts of Total Installed VPP Generation Capacity on Indices

A sensitivity study was conducted for investigating the impacts of changes in the total installed VPP generation capacity on the VPP performance indices and the system reliability indices. For conducting these studies using the RBTS along with its Bus 4 distribution network, the total rated VPP generation capacity was increased from 16 MW to 48 MW in increments of 8 MW (in other words, rated capacity of individual DGs was increased from 1 MW to 3 MW in increments of 0.5 MW) while keeping the types and locations of the DGs the same as those specified in Section 3.2 and shown in Fig. 3.1. All remaining parameters used for obtaining the results presented in this section are as mentioned in Section 3.4.1.

The family of PDFs representing the corresponding equivalent VPP models developed using the augmented RBTS Bus 4 distribution network of Fig. 3.1 with respect to changes in the total installed VPP generation capacity is presented in Fig. 3.6. An increase in the total rated VPP generation capacity causes a corresponding increase in the number of states encountered during the simulation process where the VPP operates in the ‘Producer’ mode ($P_{VPP,ij} \geq 0$). This in turn results in a gradual increase in the mean VPP outputs representing the expected values of the PDFs of Fig. 3.6, thereby causing the concerned distributions to progressively shift to the right of the X-axis along with a corresponding increase in the total installed VPP generation capacity.

A comparison of the VPP performance and system reliability indices obtained using the RBTS along with its Bus 4 distribution network as a function of the total installed VPP generation capacity is provided in Table 3.5. An increase in the amount of generation capacity at the VPP’s disposal results in a steady improvement in the VPP’s performance as shown in the table. An increase in the energy injections from the DGs with respect to a given distribution network test bed also leads to increased internal

network congestions, and the formulation (3.1) – (3.5) accordingly needs to make increased curtailments from these DGs in order to maintain all distribution network line flows within appropriate limits. This is numerically demonstrated in Table 3.5 through the sharp spike in the ERENU value once the VPP generation capacity exceeds 40 MW. Similar to the trend observed in the VPP performance indices, the system reliability indices are also seen to be steadily improving along with a corresponding increase in the total installed VPP generation capacity in Table 3.5.

Fig. 3.6 Family of PDFs representing equivalent VPP models developed using augmented RBTS Bus 4 distribution network

TABLE 3.5

COMPARISON OF INDICES OBTAINED USING RBTS AS A FUNCTION OF TOTAL INSTALLED VPP GENERATION CAPACITY

<i>VPP performance indices ↓</i>	<i>Total installed VPP generation capacity MW)</i>				
	16	24	32	40	48
MVPPE (MWh/year)	0	19.211	188.27	1.774×10^3	6.4016×10^3
ERENU (MWh/year)	0	0	0	0.647	195.3857
ESGD (MWh/year)	5.2968×10^4	7.9454×10^4	1.0594×10^5	1.3243×10^5	1.5872×10^5
ESGS (MWh/year)	5.2044	6.5971	7.5475	8.1988	8.653
<i>System reliability indices ↓</i>					
LOLF (occurrences/year)	0.1339	0.101	0.0794	0.0618	0.0488
LOLE (hours/year)	0.5545	0.3935	0.2833	0.2066	0.1584
LOEE (MWh/year)	4.67	3.277	2.327	1.6753	1.2710

Fig. 3.7 Family of PDFs representing equivalent VPP models developed using augmented IEEE 69-bus distribution network

TABLE 3.6

COMPARISON OF INDICES OBTAINED USING RTS AS A FUNCTION OF TOTAL INSTALLED VPP GENERATION CAPACITY

<i>VPP performance indices ↓</i>	<i>Total installed VPP generation capacity (MW)</i>				
	52	78	104	130	156
MVPPE (MWh/year)	0	0	1.6689	136.5001	1.4125×10^3
ERENU (MWh/year)	0	0	8.7254	123.5825	534.08
ESGD (MWh/year)	1.6615×10^5	2.4923×10^5	3.3231×10^5	4.153×10^5	4.9789×10^5
ESGS (MWh/year)	178.4364	256.3358	327.6836	392.6626	477.27
<i>System reliability indices ↓</i>					
LOLF (occurrences/year)	1.6867	1.5796	1.4975	1.3905	1.3783
LOLE (hours/year)	7.9806	7.4065	6.8407	6.3235	6.1464
LOEE (MWh/year)	976.6203	898.7208	827.3731	762.3940	748.06

For conducting these sensitivity studies using the RTS along with the IEEE 69-bus 4 distribution network, the total rated VPP generation capacity was increased from 52 MW to 156 MW in increments of 26 MW (in other words, rated capacity of individual DGs was increased from 2 MW to 6 MW in increments of 1 MW) while keeping the types and locations of the DGs the same as those specified in Section 3.2 and shown in Fig. 3.2. Similar to Fig. 3.6, the family of PDFs representing the corresponding equivalent VPP models developed using the augmented IEEE 69-bus distribution network of Fig. 3.2 with respect to changes in the total installed VPP generation capacity is presented in Fig. 3.7. Finally, similar

to Table 3.5, a comparison of the VPP performance and system reliability indices obtained for the RTS as a function of the total installed VPP generation capacity is provided in Table 3.6.

3.4.5. Impacts of Internal Composition of VPP's DG Mix on Indices

An additional sensitivity analysis was carried out for investigating the impacts of changes in the internal composition of the VPP's DG mix on the VPP performance indices and the system reliability indices. For conducting these studies, four sets of simulations were run by varying the composition of the DG mix according to the following four scenarios:

- Case A – Only WTGs
- Case B – Only PV systems
- Case C – WTGs and PV systems (no gas turbines, 50:50 share of installed capacity between WTGs and PV systems)
- Case D – WTGs, PV systems and gas turbines (corresponding to the configuration mentioned in Section 3.4.1)

The locations, numbers and sizing of the DGs were kept the same as those specified in Sections 3.2 and 3.4.1. All remaining parameters used for obtaining the results presented in this section are as mentioned in Section 3.4.1. Comparisons of the VPP performance and system reliability indices obtained for the RBTS (with RBTS Bus 4 distribution network) and the RTS (with IEEE 69-bus distribution network) as a function of the internal composition of the VPP's DG mix are presented in Tables 3.7 and 3.8 respectively.

As can be observed from the tables, the intermittencies associated with the wind resource at the selected site (refer to Sections 2.5 and 2.7 for more details) are far higher than those pertaining to the solar, and this is reflected by poorer values of the system reliability indices as well as the average annual energy contributions from the DGs (ESGS + ESGD) for Case A as compared to the corresponding values for Case B. The LOLF, which quantifies the expected number of system transitions from the success to the failure state per year, can be found to be the lowest for Case C amongst Cases A, B and C. This is owing to the fact that the energy outputs from the WTGs and PV systems tend to complement each other during hours of shortages of either resource. The ERENU values are a function of the locations of the renewable DGs vis-à-vis the surrounding distribution network constraints, and their variations with respect to the internal composition of the VPP's DG mix are illustrated in Tables 3.7 and 3.8. Replacing the gas turbines in the VPP's DG mix by intermittent renewables leads to sharp reductions in the annual average energy contributions from the DGs (e.g., ESGS + ESGD values for Case A are almost half of the corresponding values for Case D). Since the renewable DG outputs are assumed to be fully correlated in this thesis, hours with strong winds or solar irradiances produce considerable spikes in the corresponding

energy outputs from the VPP for scenarios with only one type of renewable generator in the VPP's DG mix. The MVPPE values for Cases A and B are therefore found to be generally higher than their Case D counterparts, while that for Case C (no conventional DG support and a mix of renewable DG types with negative correlation between the wind and solar resources for the selected site) is the lowest. Finally, the VPP's total energy outputs as well as the overall system's performance can be observed to be the best for Case D with a mix of renewable and conventional DGs in the VPP's portfolio.

TABLE 3.7
COMPARISON OF INDICES OBTAINED USING RBTs AS A FUNCTION OF INTERNAL COMPOSITION OF VPP'S DG MIX

<i>VPP performance indices ↓</i>	<i>Internal composition of VPP's DG mix</i>			
	Case A	Case B	Case C	Case D
MVPPE (MWh/year)	6.3662 X 10 ³	1.5786 X 10 ⁴	1.8939 X 10 ³	6.4016 X 10 ³
ERENU (MWh/year)	175.1972	229.5559	195.5343	195.3857
ESGD (MWh/year)	7.9309 X 10 ⁴	9.748 X 10 ⁴	8.8395 X 10 ⁴	1.5872 X 10 ⁵
ESGS (MWh/year)	4.7679	5.5153	6.6121	8.653
<i>System reliability indices ↓</i>				
LOLF (occurrences/year)	0.1357	0.1439	0.1309	0.0488
LOLE (hours/year)	0.6217	0.4059	0.4265	0.1584
LOEE (MWh/year)	5.4031	3.5308	3.7514	1.2710

TABLE 3.8
COMPARISON OF INDICES OBTAINED USING RTS AS A FUNCTION OF INTERNAL COMPOSITION OF VPP'S DG MIX

<i>VPP performance indices ↓</i>	<i>Internal composition of VPP's DG mix</i>			
	Case A	Case B	Case C	Case D
MVPPE (MWh/year)	5.7152 X 10 ³	1.0455 X 10 ⁴	485.1955	1.4125 X 10 ³
ERENU (MWh/year)	1.7192 X 10 ³	5.9903 X 10 ³	534.363	534.08
ESGD (MWh/year)	2.5628 X 10 ⁵	3.1137 X 10 ⁵	2.8707 X 10 ⁵	4.9789 X 10 ⁵
ESGS (MWh/year)	249.665	359.8461	318.7408	477.27
<i>System reliability indices ↓</i>				
LOLF (occurrences/year)	1.8203	1.6958	1.6396	1.3783
LOLE (hours/year)	8.6884	6.7235	7.3177	6.1464
LOEE (MWh/year)	1.0753 X 10 ³	808.4527	889.5199	748.06

3.5. Conclusions

This chapter introduces a general Monte Carlo sequential simulation based methodology for performing generation adequacy assessment of power systems incorporating an aggregated probabilistic model of distribution network components (DGs and loads) and features (topology and constraints) in the form of a VPP. The equivalent VPP model is represented using a PDF, and different aspects of its performance are quantified using suitably defined indices. The overall system reliability improvements associated with the VPP's integration are also presented in this chapter. Sensitivity studies are conducted for investigating the impacts of variations in the total installed VPP generation capacity as well as the internal composition of VPP's DG mix on the VPP performance and system reliability indices. The

results presented in this chapter can offer valuable insights to the DNO (or any relevant private player handling the VPP's operations) regarding important facets of the VPP's performance from its own as well as from the original system's perspective.

CHAPTER 4

GENERATION ADEQUACY ASSESSMENT USING AUGMENTED VPP MODEL INCORPORATING ESDs

This chapter investigates the impacts of incorporating ESDs into a VPP model and subsequently using it for performing generating system adequacy studies. A linearized multi-stage optimization formulation is proposed for combining the stochastic hourly-output based models of distribution network components like DGs, ESDs and loads into an aggregated probabilistic representation of the VPP, while also incorporating into it network-specific information like topology and constraints. Several modes pertaining to the charging/discharging of the distributed ESDs are integrated with the different stages of the optimization formulation using a fair energy allocation based operating strategy. Similar to Chapter 3, the VPP is modelled using the augmented RBTS Bus 4 and IEEE 69-bus distribution networks, and the overall generation adequacy studies incorporating the VPP are carried out on the RBTS and the IEEE RTS respectively using a sequential simulation algorithm. The VPP performance indices introduced in Chapter 3 are suitably modified for quantifying the impacts of the ESDs' incorporation on the VPP profile. Finally, sensitivity studies are carried out for analysing the impacts of variations in the ESD rated capacities, the ESD charging/discharging periods as well as the load forecast uncertainty on the VPP performance and system adequacy indices.

4.1. Introduction

4.1.1. Literature Review

A variety of methodologies have been presented in the published literature [20, 68–74] for performing reliability evaluation of power systems incorporating different combinations of distribution network components like DGs, ESDs and loads. References [68–69] present a comprehensive reliability assessment methodology for distribution networks by categorizing consumers according to customer load sectors as well as network voltage ratings. Different DG and ESD scenarios are considered, and the time-varying load curve for a given sector is decomposed according to the energy end use and combined with an empirical fault probability distribution function for evaluating distribution network reliability. References [70] and [71] analyse the impacts of renewable energy dispatch restrictions, system spinning reserve requirements as well as internal configuration of the DER portfolio (comprising WTGs, PV systems, conventional generators and ESDs) on the long-term and operational adequacy assessment of generating systems. A sequential simulation based methodology for performing generation adequacy evaluation including WTGs and ESDs is proposed in [72], wherein three different strategies for operating

the ESDs in conjunction with the WTGs are presented and their relative benefits analysed. Composite system adequacy assessment frameworks incorporating WTGs and ESDs on the distribution side are presented in [73] and [74]. While [73] considers detailed failure analysis and degradation of individual battery system components, the adopted system operating strategy in [74] enables the ESDs to export some of their stored energy to the external grid.

4.1.2. Motivations

Several deficiencies can be observed in the literature reviewed in Section 4.1.1. While [20] fails to incorporate internal constraints of the distribution network in its proposed reliability evaluation methodology, no indices are presented in [68] and [69] which can quantify the aggregated capabilities of the DGs and ESDs to export surplus energy to the external grid. Additionally, [68–69] do not quantify the VPP's contributions in improving overall system adequacy at HLI. While [70–72] address this problem by quantifying the DERs' contributions in improving overall generation adequacy, these are still modelled as lumped components and all associated distribution network information like topology and constraints are ignored. A similar lumped treatment of WTGs and ESDs is also carried out in [73]. Reference [74] models the ESDs' participation in supplying energy to the external grid during load curtailment events in the bulk power system; however, the amount of energy exported by the DERs is not explicitly quantified. While Chapter 3 addresses the limitations discussed above, the generation adequacy studies presented there do not incorporate ESDs into the VPP's generation portfolio. This chapter bridges the gaps in the reviewed literature as well as in the work presented in Chapter 3 by proposing a general methodology for investigating the impacts of incorporating ESDs into a VPP model and subsequently using it for performing generation adequacy studies [31].

4.1.3. Contributions

The primary contributions of this chapter are as follows: 1) A linear programming based multi-stage optimization formulation is proposed for combining the stochastic hourly-output based models of several DGs, ESDs and loads along with distribution network features like topology and constraints into an aggregated probabilistic representation of the VPP. Several modes pertaining to the charging/discharging of the distributed ESDs are integrated with the formulation using a fair energy allocation based operating strategy. 2) The VPP indices MVPPE, ERENU, ESGS and ESGD are suitably modified for quantifying the impacts of the ESDs' incorporation on the performance of the VPP model. 3) Sensitivity studies are carried out for analysing the impacts of variations in the ESD rated capacities, the ESD charging/discharging periods as well as the load forecast uncertainty on the VPP performance and system adequacy indices.

4.2. Distribution Network Layout Showing Locations of Components Constituting VPP Model

Similar to the results presented in Chapter 3, two sets of simulation runs were performed for testing the overall methodology proposed in this chapter. The first set of simulations was run using the RBTS [24], with the RBTS Bus 4 distribution network [26] used for modelling the VPP as shown in Fig. 4.1. Relevant details of the RBTS are presented in Appendix A. Several DGs and ESDs are assumed to be integrated with the network, with the locations, numbers and types of the added DGs being the same as presented in Section 3.2 and depicted in Fig. 3.1. The assumed configuration of the added ESDs in Fig. 4.1 is as follows: an ESD each at nodes 8, 19, 24 and 32 of the RBTS Bus 4 distribution network. As mentioned in Section 3.2, the VPP model corresponding to the first set of simulations is characterized by an annual peak load of 40 MW, with its internal network assumed to be located at Bus 4 of the RBTS.

Fig. 4.1 Schematic representation of RBTS Bus 4 distribution network showing locations of DGs, ESDs and loads

Like in Chapter 3, the second set of simulations was run using the IEEE RTS [25], with the IEEE 69-bus distribution network [27] used for modelling the VPP as shown in Fig. 4.2. Relevant details of the RTS are presented in Appendix B. Several DGs and ESDs are assumed to be integrated with the network, with the locations, numbers and types of the added DGs being the same as presented in Section 3.2 and depicted in Fig. 3.2. The assumed configuration of the added ESDs in Fig. 4.2 is as follows: an ESD each at nodes 12, 29, 39, 44 and 47, and two ESDs at node 63 of the IEEE 69-bus distribution network. As

mentioned in Section 3.2, the VPP model corresponding to the second set of simulations is characterized by an annual peak load of 181 MW, with its internal network assumed to be located at Bus 19 of the RTS.

Fig. 4.2 Schematic representation of IEEE 69-bus distribution network showing locations of DGs, ESDs and loads

4.3. Overall Methodology Used for Performing Generation Adequacy Studies

4.3.1. Modelling of Distributed Energy Resources

Details of the modelling of renewable (WTGs and PV systems) and conventional (gas turbines) DGs considered in the VPP's distributed energy resources (DER) portfolio are presented in Section 3.3.1. While different energy storage technologies are commercially available in today's markets, a generic battery unit is used for modelling the ESDs in this chapter. The ESDs are characterized by the following parameters: rated capacity ' $E_{R,s}$ ' (MWh), maximum and minimum state-of-charge ' SoC_{max} , SoC_{min} ' (%),

charging and discharging periods ' T_{ch}, T_d ' (hours), and charging and discharging efficiency ' η_{ch}, η_d ' (%). Assuming that the batteries undergo charging from ' SoC_{min} ' to ' SoC_{max} ' at a linear rate over the span of ' T_{ch} ' hours (or conversely, discharge from ' SoC_{max} ' to ' SoC_{min} ' at a linear rate over the span of ' T_d ' hours) [72], the maximum energy (MWh) that an ESD ' s ' can consume/dispatch (assuming $T_{ch}=T_d$) over an hour is given by:

$$E_{max,s} = (SoC_{max} - SoC_{min}) * E_{R,s} / T_{ch}, \forall s \in S \quad (4.1)$$

where ' S ' denotes the set of all ESDs integrated in the distribution network test bed under consideration. Considering the generic battery unit modelled in this study, the assumed charging/discharging profile is also generic in nature. It may therefore be noted that other alternatives (perhaps a particular charging and/or discharging profile may be more suitable for a specific storage technology) can also be used as per the requirements of a given study.

4.3.2. Multi-Stage Optimization Formulation for Developing Overall VPP Model Incorporating ESDs

This section presents the multi-stage network flow based linear programming optimization formulation used for combining the stochastic hourly-output based models of several DGs, ESDs and loads along with distribution network information like topology and constraints into an aggregated probabilistic representation of the VPP. The generic VPP operating policy which serves as the motivation for this formulation is also described.

4.3.2.1. Stage I – Compute Optimal VPP Output Without ESDs

This stage of the formulation is essentially the same as that presented in Section 3.3.3. Without modelling the ESDs in this stage, the VPP aggregator determines the maximum energy that it can export to the external grid after meeting internal network demands and constraints. The output of this stage is the decision variable ' $P_{VPP,ij}$ ' defined in (3.6), which quantifies the optimal VPP output after satisfying internal network demands and constraints.

4.3.2.2. Stage II.A – Compute Optimal VPP Output in ESD Charging Mode

This stage is activated if ' $P_{VPP,ij}$ ' computed in Stage I above is ≥ 0 , i.e., the VPP aggregator has surplus energy which it can export to the external grid. This stage recalculates the optimal VPP output computed in Stage I after incorporating a fair energy allocation scheme for charging as many of the distributed ESDs as possible using either the surplus energy ' $P_{VPP,ij}$ ' or the DG curtailments carried out in the previous stage. Several publications in the literature propose optimization formulations for fair allocation of limited and/or constrained resources (e.g. DG outputs) amongst a number of candidate loads

(e.g. ESDs in charging mode), while maximizing the global charge allocation efficiency [75] or minimizing the curtailments in the ESD charging energy requirements [76]. The strategy adopted in this thesis aims to allocate the energy available for charging the ESDs in such a way that produces a balanced SoC profile for the batteries. The overall objective of this stage is achieved by minimizing the curtailments of the DG outputs as well as the ESD charging energy requirements, while assigning different priorities to the disparate curtailment components and ensuring that relevant constraints are satisfied. The mathematical formulation for this stage is presented below.

Objective function:

$$\min \{ (w^r * \sum C_{k,ij}^r) + (w^c * \sum C_{k,ij}^c) + \sum (w^s * C_{s,ij}) \}, \forall k \in K, \forall s \in S \quad (4.2)$$

Constraints:

$$\sum C_{k,ij}^r + \sum C_{k,ij}^c \leq C_{opt,ij}, \forall k \in K \quad (4.3)$$

$$E_{max,s,ij}^{ch} = \min(E_{s,ij} + E_{max,s}, SoC_{max} * E_{R,s}) - E_{s,ij}, \forall s \in S \quad (4.4)$$

$$\sum P_{l,n,ij}^{in} + \sum G_{k,max,n,ij} + \sum C_{s,n,ij} = D_{n,ij} + \sum P_{l,n,ij}^{out} + \sum C_{k,n,ij} + \left(\frac{1}{\eta_{ch}}\right) * \sum E_{max,s,n,ij}^{ch}, \forall n \in N \quad (4.5)$$

$$0 \leq C_{s,ij} \leq \left(\frac{1}{\eta_{ch}}\right) * E_{max,s,ij}^{ch}, \forall s \in S \quad (4.6)$$

$$P_{l,0,ij}^{out} \geq 0, \text{ node } n = 0 \quad (4.7)$$

Decision variables:

$$E_{s,i+1,j} = E_{s,ij} + \{E_{max,s,ij}^{ch} - (\eta_{ch} * C_{s,ij})\}, \forall s \in S \quad (4.8)$$

$$P_{0,ij} = \sum_{k \in K} (G_{k,max,ij} - C_{k,ij}) - \sum_{n \in N} D_{n,ij} - \left(\frac{1}{\eta_{ch}}\right) * \sum_{s \in S} (E_{s,i+1,j} - E_{s,ij}) \quad (4.9)$$

where ‘ $C_{s,ij}$ ’ (MWh) and ‘ w^s ’ respectively denote the optimal curtailment and the weight assigned to the curtailment of the charging energy requirement ‘ $E_{max,s,ij}^{ch}$ ’ (MWh) from ESD ‘ s ’ for hour ‘ i ’; ‘ $C_{opt,ij}$ ’ (MW) is the solution of the linear programming problem defined in (3.1) – (3.5), i.e., $C_{opt,ij} = \sum C_{k,ij}^r + \sum C_{k,ij}^c$; ‘ $E_{s,ij}$ ’ and ‘ $E_{s,i+1,j}$ ’ (MWh) represent the stored energy in ESD ‘ s ’ in consecutive hours ‘ i ’ and ‘ $i+1$ ’ respectively; ‘ $\sum G_{k,max,n,ij}$ ’, ‘ $\sum C_{k,n,ij}$ ’, ‘ $\sum C_{s,n,ij}$ ’ and ‘ $\sum E_{max,s,n,ij}^{ch}$ ’ are aggregated representations of ‘ $G_{k,max,ij}$ ’, ‘ $C_{k,ij}$ ’, ‘ $C_{s,ij}$ ’ and ‘ $E_{max,s,ij}^{ch}$ ’ (respectively) for all DGs and ESDs associated with a given node ‘ n ’ of the distribution network; ‘ $P_{l,0,ij}^{out}$ ’ (MW) refers to the total outgoing power flow at node ‘0’ of the distribution network test bed under consideration, the positive sign convention used for which is as shown in Figs. 4.1 and 4.2; and *decision variable* ‘ $P_{0,ij}$ ’ (MW) denotes the optimal (maximum) energy that the VPP aggregator can export to the external grid after satisfying internal network demands (loads + ESD charging energy requirements) and constraints. Note that constraints (3.3) – (3.5) are also applicable over and above those already presented as part of the formulation (4.2) – (4.9).

Like in Section 3.3.3, the adopted VPP operating policy prioritizes the dispatch from renewable DGs over that from the conventional units by selecting $w^r > w^c$ in (4.2). Additionally, in order to implement the fair charging energy allocation strategy described above, the battery SoCs are sorted in an ascending order (low to high) for every hour ‘i’ and the set of weights $[w^s]_{\forall s \in S}$ are dynamically chosen such that ESDs with lower SoCs are assigned higher weights than those having higher SoCs. This implies that in case of limited availability of energy for charging the ESDs, the same is allocated on a priority basis to batteries with lower SoCs. Equation (4.3) ensures that the minimum energy produced by the DGs equals the optimal value computed in Stage I, with the inequality included to enforce utilization of the DG curtailments from the previous stage for charging the ESDs. Equation (4.5) is an extension of (3.2) after incorporating ESDs into the nodal power conservation constraint. Inequality (4.6) enforces applicable limits on the ESD charging energy curtailments. Constraint (4.7) ensures that only the surplus energy ‘ $P_{VPP,ij}$ ’ computed in Stage I is used for charging the ESDs, i.e., the external grid is assumed not to provide any charging energy support as part of the adopted VPP operating policy.

4.3.2.3. Stage II.B – Compute Optimal VPP Output in ESD Discharging Mode

This stage is activated if ‘ $P_{VPP,ij}$ ’ computed in Stage I is < 0 , i.e., the VPP aggregator needs to import power from the external grid for meeting the energy deficit in its internal network. This stage recalculates the optimal VPP output computed in Stage I after extracting maximum permissible energy from the distributed ESDs in accordance with a fair discharging strategy adopted in this thesis. This strategy is in line with the SoC-balancing approach presented in [77], and it dispatches the ESDs in such a way that produces a balanced state-of-charge (SoC) profile for the batteries. Combined with the fair energy allocation scheme described in Section 4.3.2.2, the overall charging/discharging strategy therefore helps to avoid prolonged operation of the ESDs at/near their SoC limits which may adversely affect their lifetime and performance [77]. The objective of this stage is achieved by minimizing the dispatch curtailments from the DGs and the ESDs, while assigning different priorities to the disparate curtailment components and ensuring that relevant constraints are satisfied. The objective function for this stage is mathematically the same as (4.2) (although with a different interpretation), and is reproduced below together with the overall optimization formulation.

Objective function:

$$\min \{ (w^r * \sum C_{k,ij}^r) + (w^c * \sum C_{k,ij}^c) + \sum (w^s * C_{s,ij}) \}, \forall k \in K, \forall s \in S \quad (4.10)$$

Constraints:

$$\sum C_{k,ij}^r + \sum C_{k,ij}^c = C_{opt,ij}, \forall k \in K \quad (4.11)$$

$$E_{max,s,ij}^d = E_{s,ij} - \max(E_{s,ij} - E_{max,s}, SoC_{min} * E_{R,s}), \forall s \in S \quad (4.12)$$

$$\sum P_{l,n,ij}^{in} + \sum G_{k,max,n,ij} + \eta_d * \sum E_{max,s,n,ij}^d = D_{n,ij} + \sum P_{l,n,ij}^{out} + \sum C_{k,n,ij} + \sum C_{s,n,ij}, \forall n \in N \quad (4.13)$$

$$0 \leq C_{s,ij} \leq \eta_d * E_{max,s,ij}^d, \forall s \in S \quad (4.14)$$

$$P_{l,0,ij}^{out} \leq 0, \text{node } n = 0 \quad (4.15)$$

Decision variables:

$$E_{s,i+1,j} = E_{s,ij} - \{E_{max,s,ij}^d - (C_{s,ij}/\eta_d)\}, \forall s \in S \quad (4.16)$$

$$P_{0,ij} = \sum_{k \in K} (G_{k,max,ij} - C_{k,ij}) - \sum_{n \in N} D_{n,ij} - \eta_d * \sum_{s \in S} (E_{s,i+1,j} - E_{s,ij}) \quad (4.17)$$

where ‘ $C_{s,ij}$ ’ (MWh) denotes the optimal curtailment of the dispatchable energy ‘ $E_{max,s,ij}^d$ ’ (MWh) from ESD ‘ s ’ for hour ‘ i ’; ‘ $\sum E_{max,s,n,ij}^d$ ’ (MWh) is an aggregated representation of ‘ $E_{max,s,ij}^d$ ’ for all ESDs associated with a given node ‘ n ’ of the distribution network; and *decision variable* ‘ $P_{0,ij}$ ’ (MW) denotes the optimal (minimum) energy that the VPP aggregator needs to import from the external grid for meeting the energy deficit in its internal network. The energy deficit equals the demand that is left unsatisfied after optimally dispatching the VPP’s constituent DGs and ESDs. Note that constraints (3.3) – (3.5) are also applicable over and above those already presented as part of the formulation (4.10) – (4.17).

The adopted VPP operating policy prioritizes the dispatches from the DERs in the following order: renewable followed by conventional DGs and finally ESDs. This priority order is enforced by selecting $w^r > w^c > [w^s]_{\forall s \in S}$ in (4.10). Additionally, in order to implement the fair discharging strategy described above, the battery SoCs are sorted in a descending order (high to low) for every hour ‘ i ’ and the set of weights ‘ $[w^s]_{\forall s \in S}$ ’ are dynamically chosen such that ESDs with higher SoCs are assigned higher weights than those having lower SoCs. This implies that batteries with higher SoCs are dispatched on a priority basis for meeting as much of the energy deficit in the VPP’s internal network as possible. Since the sequence of ESDs in the sorted order changes from hour to hour, this together with the dynamic weight selection strategy described in Section 4.3.2.2 (for charging ESDs) therefore ensures that the SoC profile of the batteries is smoothened over the long term. Equation (4.11) ensures that the total DG output equals the optimal value computed in Stage I. Equations (4.13) and (4.14) are counterparts of (4.5) and (4.6) respectively, with the ESD terms corresponding to the battery discharging mode. Constraint (4.15) ensures that the discharged energy from the ESDs is used only for covering the deficit in the VPP’s internal network demand, i.e., the batteries are assumed not to provide any support for satisfying external grid demand as part of the adopted VPP operating policy.

4.3.2.4. Stage II.C – Update Optimal DG Outputs and Battery SoCs in ESD Constrained Charging Mode

This stage is executed using the solutions obtained from Stage II.B (Section 4.3.2.3). Considering node 43 of the distribution network layout presented in Fig. 4.2 as an example, it may be observed that the outputs of one/more of the downstream DGs may sometimes need to be curtailed owing to line flow

constraints in the upstream network. Keeping in mind the DER dispatch priority order enforced in Stage II.B (renewable followed by conventional DGs and finally ESDs), this would imply that one/more of the downstream ESDs would also not be able to discharge in such a scenario. This stage is specifically introduced to take care of such generic scenarios, wherein DG curtailments carried out in Stage II.B are used for supplying as much of the charging energy requirements as possible from ESDs that are not discharged in the previous stage. The rationale behind this is to reduce wastage of DG outputs by charging up relevant ESDs, which can then be discharged in future hours for bridging the energy deficit in the VPP's internal network. To implement this philosophy, the ESD dispatch curtailment solutions $[C_{s,ij}]_{\forall s \in S}$ obtained from (4.10) are used for sorting the ESDs into the following two sets: 'S_d' containing all ESDs 's' that are discharged in Stage II.B and 'S_{ch}' containing the remaining batteries. This stage then proceeds on similar lines as Stage II.A (ESD charging mode), with target ESDs for charging being drawn from set 'S_{ch}' only. Charging energy requirements of candidate ESDs are met using the fair energy allocation scheme described in Section 4.3.2.2, while ensuring that relevant constraints are satisfied. The optimization formulation for this stage is presented below, with the objective function reproduced from (4.2) for continuity sake.

Objective function:

$$\min \{ (w^r * \sum C_{k,ij}^r) + (w^c * \sum C_{k,ij}^c) + \sum (w^s * C_{s,ij}) \}, \forall k \in K, \forall s \in S_{ch} \quad (4.18)$$

Constraints:

$$\sum P_{l,n,ij}^{in} + \sum G_{k,max,n,ij} + \eta_d * \sum_{\forall s \in S_d} (E_{s,n,ij} - E_{s,n,i+1,j}^*) + \sum_{\forall s \in S_{ch}} C_{s,n,ij} = D_{n,ij} + \sum P_{l,n,ij}^{out} + \sum C_{k,n,ij} + \left(\frac{1}{\eta_{ch}} \right) * \sum_{\forall s \in S_{ch}} E_{max,s,n,ij}^{ch}, \forall n \in N \quad (4.19)$$

$$P_{l,0,ij}^{out} = P_{0,ij}^*, \text{ node } n = 0 \quad (4.20)$$

Decision variables:

$E_{s,i+1,j}$ and $P_{0,ij}$

where 'C_{s,ij}' is as defined in Section 4.3.2.2; 'ΣE_{s,n,ij}' and 'ΣE_{s,n,i+1,j}' (MWh) are aggregated representations of 'E_{s,ij}' and 'E_{s,i+1,j}' (respectively) for all ESDs associated with a given node 'n' of the distribution network; and 'E_{s,i+1,j}^{*}' and 'P_{0,ij}^{*}' represent the optimal solutions obtained using (4.16) and (4.17) respectively. Note that constraints (3.3) – (3.5), (4.3) – (4.4) and (4.6) are also applicable over and above those already presented as part of the formulation (4.18) – (4.20), with (4.4) and (4.6) only pertaining to all ESD s ∈ S_{ch}. While *decision variable* 'E_{s,i+1,j}' (∀s ∈ S_{ch}) is computed using (4.8), 'P_{0,ij}' can be interpreted in the same way as presented in Section 4.3.2.3 and its value equals 'P_{0,ij}^{*}'.

The selection of weights 'w^r', 'w^c' and '[w^s]_{∀s ∈ S_{ch}}' is done in a similar manner as that described in Section 4.3.2.2. Equation (4.19) is an extension of (3.2), with relevant ESDs incorporated in

the discharging and/or constrained charging modes. Constraint (4.20) ensures that only the DG curtailments carried out in Stage II.B are used for charging concerned ESDs.

4.3.2.5. Additional Discussions on Proposed Formulation and VPP Operating Policy

Like in Chapter 3, the linear programming based optimization formulations presented in Sections 4.3.2.1 – 4.3.2.4 are executed using the ‘*linprog*’ function of the MATLAB optimization toolbox [63]. Note that the weights ‘ w^r ’, ‘ w^c ’ and ‘ $[w^s]$ ’ are all positive quantities, and one needs to be only concerned about their relative (as opposed to individual) magnitudes while assigning corresponding values in (4.2), (4.10) and (4.18). It may also be noted that in the context of the formulations presented in Sections 4.3.2.1 – 4.3.2.4, the term “multi-stage” is used simply to refer to a hierarchical optimization framework, wherein individual “layers” or “stages” of the problem are solved in the following sequence for every hour ‘ i ’. Stage I is executed first, and its output ‘ $P_{VPP,ij}$ ’ is used to determine whether Stage II.A ($P_{VPP,ij} \geq 0$, ESDs in charging mode) or Stage II.B ($P_{VPP,ij} < 0$, ESDs in discharging mode) is executed next. In case Stage II.B is solved, the outputs (‘ $E_{s,i+1,j}^*$ ’ and ‘ $P_{0,ij}^*$ ’) of this stage are then used for executing Stage II.C. The sequence of solution of the overall optimization problem is also depicted in the algorithm flowchart of Fig. 4.3.

Since decision variable ‘ $P_{0,ij}$ ’ denotes the optimal energy balance in the VPP’s internal network after incorporating ESDs, the distribution associated with this random variable is therefore the aggregated probabilistic representation of the augmented VPP model at the transmission grid interface. The adopted VPP operating policy in this chapter assumes that for every hour ‘ i ’ when $P_{0,ij} \geq 0$, the VPP aggregator is able to offer this excess energy to the ISO for being dispatched on a priority basis for meeting as much of the external grid demand as possible. For hours when $P_{0,ij} < 0$, the system operator supplies the energy deficit in the VPP’s internal network by dispatching generating units from the external grid. The rationale behind adoption of this policy is to model the VPP as a self-sustained unit, wherein the aggregator attempts to charge up the ESDs as much as possible after satisfying internal network demands and constraints. The ESDs are appropriately discharged during hours of deficit, thereby minimizing the import of energy from the external grid. Additionally, the energy export based operating strategy for hours when $P_{0,ij} \geq 0$ maximizes the revenue generation opportunities for the VPP aggregator.

Similar to Chapter 3, the presented optimization formulations along with the adopted VPP operating policy for this chapter are generic in nature, and can be applied to any distribution network characterized by any internal configuration of DGs and ESDs. Note that alternative formulations as well as operating policies can also be chosen as per the requirements of a given study. The selected operating policy further assumes that the sizing, siting and the penetration levels of the modelled DERs do not violate applicable hosting capacity limits for the distribution network test bed under consideration,

thereby implying that network security is not compromised and all voltages are within acceptable bounds. These assumptions are routinely made while performing long-term system adequacy studies at HLI [15, 28, 74].

4.3.3. Quantification of VPP's Performance Incorporating ESDs

Several indices are defined in Section 3.3.5 for quantifying different aspects of the VPP's performance. These are suitably modified in this section using decision variable ' $P_{0,ij}$ ' for investigating the impacts of the ESDs' incorporation on the augmented VPP model's performance. All index definitions and units are presented in Section 3.3.5.

The reformulated MVPPE corresponding to the augmented VPP model incorporating ESDs is computed as follows:

$$MVPPE = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} \max(0, P_{0,ij}) \right) / N_y \quad (4.21)$$

where ' $P_{0,ij}$ ' is obtained using (4.9) or (4.17).

The reformulated ERENU corresponding to the augmented VPP model incorporating ESDs is computed as follows:

$$ERENU = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} \{ \sum C_{k,ij}^r \} \right) / N_y \quad (4.22)$$

where ' $\sum C_{k,ij}^r$ ' is obtained using (4.2) or (4.18).

Finally, the reformulated ESGS and ESGD indices corresponding to the augmented VPP model incorporating ESDs are computed as follows:

If $P_{G,ij} \geq P_{D,ij}$:

$$ESGS_{ij} = 0 \quad (4.23)$$

$$ESGD_{ij} = P_{0,ij} + \sum_{n \in N} D_{n,ij} \quad (4.24)$$

elseif $(P_{G,ij} < P_{D,ij}) \& (P_{G,ij} + P_{0,ij} + \sum_{n \in N} D_{n,ij} \geq P_{D,ij})$:

$$ESGS_{ij} = P_{D,ij} - P_{G,ij} \quad (4.25)$$

$$ESGD_{ij} = P_{0,ij} + \sum_{n \in N} D_{n,ij} - ESGS_{ij} \quad (4.26)$$

else $(P_{G,ij} + P_{0,ij} + \sum_{n \in N} D_{n,ij} < P_{D,ij})$:

$$ESGS_{ij} = P_{0,ij} + \sum_{n \in N} D_{n,ij} \quad (4.27)$$

$$ESGD_{ij} = 0 \quad (4.28)$$

$$X = \frac{(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} X_{ij})}{N_y}, X = ESGS \text{ or } ESGD \quad (4.29)$$

where 'P_{0,ij}' is obtained using (4.9) or (4.17).

4.3.4. Algorithm for Performing Generation Adequacy Studies Using Augmented VPP Model

Fig. 4.3 Flowchart of Monte Carlo sequential algorithm used for performing generation adequacy studies

The flowchart of the Monte Carlo sequential simulation algorithm [28] used for performing generation adequacy studies using the augmented VPP model developed in Section 4.3.2 is presented in Fig. 4.3. Failures and repairs are modelled for the VPP's constituent DGs as well as for the original system generating units. Component failures are represented using a two-state (Up/Down) model. ESDs are assumed to be completely reliable. Multi-state component failure modes as well as failures in the ESDs can, however, be easily modelled as per the requirements of a given study.

The dash-dotted (inner) rectangle in Fig. 4.3 highlights the tasks that need to be executed for incorporating ESDs into the generic VPP model formulated in Chapter 3. The steps to be performed for incorporating the augmented VPP model including ESDs into the generation adequacy studies conducted in this chapter are contained within the dashed (outer) rectangle in Fig. 4.3.

The Monte Carlo sequential simulation approach is used throughout this thesis for a variety of reasons. Chronological simulations naturally allow one to accurately track and model the inter-temporal variations in the battery SoCs. Hourly correlations between the renewable DG outputs and the VPP's internal network demands can also be correctly captured using sequential simulations, thereby producing a realistic and accurate realization of the equivalent VPP model along with its associated indices. Performing adequacy assessment using this approach also helps to generate the probability distributions of key indices for the VPP and the system, which can in turn provide helpful insights to planners regarding the expected values as well as the variability of the respective indices. Finally, the sequential technique enables one to easily compute the actual frequency and duration indices for the overall system, which are otherwise difficult to obtain using, for example, the state sampling approach [28].

It is to be, however, noted that the application of the sequential simulation approach to larger test systems would result in an exponential increase in computation time. Hybrids of available reliability evaluation methodologies, e.g. a combination of analytical and state sampling approaches [35] as well as pseudo-sequential Monte Carlo simulation techniques [36] have therefore been used in the available literature for performing adequacy assessment incorporating intermittent resources and time-varying loads, while ensuring faster algorithm convergence. Investigation of the accuracy of the obtained results vis-à-vis the computational burden associated with the adopted reliability evaluation technique is beyond the scope of this thesis; however, this is an excellent topic for future research.

4.4. Results and Discussions

This section presents the results obtained from the investigation of the impacts of incorporating ESDs into a VPP model and subsequently using the model for performing generation adequacy studies. As mentioned in Section 4.2, two sets of simulation runs were conducted for testing the overall methodology proposed in this chapter: the first one corresponding to the RBTS coupled with its Bus 4

distribution network [24, 26], and the second set corresponding to the IEEE RTS in conjunction with the IEEE 69-bus distribution network [25, 27].

The locations, numbers and types of the added DGs and ESDs for the two test cases are presented in Section 4.2 and Figs. 4.1 and 4.2. The sizing of the modelled DGs for both sets of simulation runs are mentioned in Section 3.4.1. The assumed rated capacities of the ESDs portrayed in Fig. 4.1 are as follows: 2.5 MWh for each ESD at nodes 8, 19, 24 and 32. The assumed rated capacities of the ESDs portrayed in Fig. 4.2 are as follows: 4.5 MWh each for the ESDs at node 63, and 5 MWh each for the remaining ESDs. Other ESD parameters are assigned the following values for both sets of simulation runs: $\text{SoC}_{\max} = 100\%$, $\text{SoC}_{\min} = 20\%$, $T_{\text{ch}} = 5$ hours, $\eta_{\text{ch}} = \eta_{\text{d}} = 90\%$. The values for the charging/discharging efficiencies and the SoC limits are obtained from [20] and [72] respectively. Remaining specifications regarding the failure/repair rate data and characteristic parameter values for the DGs, the system load profile as well as the ARMA models used for predicting hourly wind speed/solar irradiance values are presented in Section 3.4.1.

4.4.1. Overall Developed VPP Model Incorporating ESDs

The augmented VPP model incorporating ESDs developed in Section 4.3.2, as characterized by the distribution associated with decision variable ' $P_{0,ij}$ ', is portrayed in Fig. 4.4. The VPP model without ESDs (as developed in Chapter 3), characterized by the distribution associated with random variable ' $P_{\text{VPP},ij}$ ', is also presented in Fig. 4.4 for comparison sake. The distributions of Fig. 4.4 pertain to the respective VPP models developed using the augmented RBTS Bus 4 distribution network.

Though the expected values of the distributions of Fig. 4.4 are nearly the same, their shapes are markedly different with a sharp spike around the $P_{0,ij} = 0$ line in the distribution corresponding to the VPP model with ESDs. Denoting the probability that random variable ' X ' lies between known values ' a ' and ' b ' as $\text{Pr}[a \leq X \leq b]$, it can be computed from Fig. 4.4 that $\text{Pr}[-0.25 \leq P_{\text{VPP},ij} \leq 0.25] = 0.0176$ whereas $\text{Pr}[-0.25 \leq P_{0,ij} \leq 0.25] = 0.0771$, which indicates a jump of over 4 times. Since the areas under both the distributions of Fig. 4.4 equal 1, this surge in the probability of occurrence of states around the $P_{0,ij} = 0$ line implies that the incorporation of ESDs into the VPP model causes an increasing number of states from both sides of the Y-axis to be squeezed towards $P_{0,ij} = 0$. This phenomenon can be explained using the formulations presented in Section 4.3.2. For all hours with the batteries in charging mode, constraint (4.7) ensures that $0 \leq P_{0,ij} \leq P_{\text{VPP},ij}$, implying that the ' $P_{0,ij}$ ' states are shifted to the left of the corresponding ' $P_{\text{VPP},ij}$ ' states. Similarly, for hours when the ESDs are in discharging mode, constraint (4.15) ensures that $P_{\text{VPP},ij} \leq P_{0,ij} \leq 0$, implying that the ' $P_{0,ij}$ ' states are now shifted to the right of the corresponding ' $P_{\text{VPP},ij}$ ' states. The cumulative impact of this is that the incorporation of ESDs causes a large number of states from both sides of the Y-axis to be gradually shifted towards the common boundary of the two above

mentioned inequality conditions, i.e., $P_{0,ij} = 0$. It may however be noted from Fig. 4.4 that the dip in the solid curve (with respect to the dotted) to the right (batteries charging) of the $P_{VPP,ij} = 0$ line is higher than that to the left (batteries discharging). This can be explained as follows. Considering that the share of intermittent renewables in the VPP's DG portfolio is 75% for the RBTS test case, decision variable ' $P_{VPP,ij}$ ' computed using (3.6) is negative for most simulation hours. This implies that the ESDs are in discharging mode (Stage II.B) for most hours 'i', thereby soon exhausting their limited stored energy and residing at/near their lowest permissible SoC levels for a majority of the simulation time span. In such a scenario, there is a very limited scope for discharging the ESDs any further even if $P_{VPP,ij} < 0$, leaving ' $P_{0,ij}$ ' minimally increased (or even unchanged) with respect to ' $P_{VPP,ij}$ '. In comparison, for hours when $P_{VPP,ij} \geq 0$, the surplus energy is immediately dispatched (Stage II.A) for meeting the huge charging energy requirements from the ESDs. This therefore makes $P_{0,ij} < P_{VPP,ij}$ for such hours, thereby shifting the original ' $P_{VPP,ij}$ ' states to the left towards the $P_{0,ij} = 0$ line. The overall impact of this is that there is a relative build-up of states in the vicinity of the $P_{0,ij} = 0$ line, with the shifting of the ' $P_{0,ij}$ ' states (with respect to ' $P_{VPP,ij}$ ') being more pronounced to the right of the Y-axis than to the left.

Fig. 4.4 Comparative portrayal of VPP models developed with and without ESDs using augmented RBTS Bus 4 distribution network

Fig. 4.5 presents the discrete PDF plots of the long term distribution of the SoC levels in individual batteries modelled in the augmented RBTS Bus 4 distribution network (refer to Fig. 4.1 for

more details). As can be observed from the figure, there is an almost 76% chance of the batteries residing in the 20% - 30% range of SoC levels over the course of the simulations. This essentially corroborates the statement made in the immediately preceding paragraph about the ESDs residing at/near their lowest permissible SoC levels for a majority of the simulation time span. The utilization efficiency of the modelled ESDs is therefore found to be low from Fig. 4.5. It should however be noted that these findings are dependent on numerous factors, e.g., the adopted VPP operating policy, ESD charging/discharging strategy as well as the simulation data used. The overall methodology proposed in this chapter is, however, generic, and can be easily used with alternative operating policies as well as datasets.

Fig. 4.5 Discrete PDF plots of SoC levels of batteries modelled in augmented RBTS Bus 4 distribution network

The impacts of the ESDs' incorporation on the overall VPP model's performance are quantified in Table 4.1 using the indices presented in Section 4.3.3. The presented indices are computed using the RBTS along with its Bus 4 distribution network. Since the excess VPP energy ' $P_{VPP,ij}$ ' is used for charging the ESDs in Stage II.A, the MVPPE corresponding to the VPP model incorporating ESDs is calculated to be about 79.13% of that obtained for the VPP model without ESDs (as developed in Chapter 3). The usage of DG curtailments for charging the ESDs in Stages II.A and II.C helps in reducing the wastage of renewable DG outputs by about 33.13%, as indicated by the ERENU values in Table 4.1. The incorporation of ESDs is found to have a very nominal impact on the calculated ESGD and ESGS values as shown in Table 4.1. The percentage contributions of the renewable (WTGs and PV generators) and

conventional (gas turbines) DGs as well as the ESDs in the computed ESGD and ESGS values are also indicated in Table 4.1.

TABLE 4.1
IMPACTS OF ESDs' INCORPORATION ON PERFORMANCE OF VPP MODEL DEVELOPED USING RBTS

<i>VPP performance indices</i>	<i>VPP model</i>	
	<i>Without ESDs</i>	<i>With ESDs</i>
MVPPE (MWh/year)	6.4016×10^3	5.0655×10^3
ERENU (MWh/year)	195.3857	130.66
ESGD (MWh/year)	1.5872×10^5	1.5851×10^5
[WTG+PV/GT/ESD] (%)	[41.7/58.3/-]	[41.36/57.93/0.71]
ESGS (MWh/year)	8.653	8.416
[WTG+PV/GT/ESD] (%)	[43.3/56.7/-]	[42.82/57.01/0.17]

Fig. 4.6 RBTS test case: (a) Breakdown of VPP's annual average DG outputs amongst end uses, and (b) Breakdown of share of energy sources in meeting VPP's internal network demand

In order to gain additional insights into the impacts of the ESDs' incorporation on the VPP's annual average energy generation/consumption patterns, a detailed break-down of the end use of the DG outputs as well as the contributions of energy sources in meeting the VPP's internal network demands are presented in the pie charts of Fig. 4.6(a) and 4.6(b) respectively. The data presented in Fig. 4.6 correspond to the RBTS test case. Fig. 4.6(a) depicts the relative share of the total energy injections from the DGs amongst the following three end uses: meeting VPP's internal network demand, charging ESDs and being exported to the external grid. It can be observed from Fig. 4.6(a) that about 95.93% of the VPP's annual average DG outputs are used for meeting its internal network demands. Similarly, Fig. 4.6(b) depicts the relative share of the following three energy sources in meeting the VPP's internal network demands: DGs,

ESDs and import from the external grid. It may be noted that even though the total installed DG capacity modelled as part of the augmented RBTS Bus 4 distribution network of Fig. 4.1 is 48 MW as against an annual peak load of 40 MW, it can be observed from Fig. 4.6(b) that about 28.73% of the VPP's annual average internal network demands need to be supplied by external grid generation. This is owing to the inherent intermittencies associated with the renewable DG outputs, which constitute 75% of the VPP's total installed DG capacity.

A comparison of the VPP models with and without ESDs, as developed using the augmented IEEE 69-bus distribution network, is presented in Fig. 4.7. Discrete PDF plots of the long term distribution of the SoC levels in individual batteries modelled in the RTS test case are presented in Fig. 4.8. The impacts of the ESDs' incorporation on the overall VPP model's performance, as computed for the RTS test case using the indices presented in Section 4.3.3, are quantified in Table 4.2. Finally, the break-down of the end use of the DG outputs as well as the contributions of energy sources in meeting the VPP's internal network demands pertaining to the RTS test case are presented in the pie charts of Figs. 4.9(a) and 4.9(b) respectively. The interpretations for the data presented in the following table and figures are on similar lines as those presented above for the RBTS test case.

Fig. 4.7 Comparative portrayal of VPP models developed with and without ESDs using augmented IEEE 69-bus distribution network

Fig. 4.8 Discrete PDF plots of SoC levels of batteries modelled in augmented IEEE 69-bus distribution network

TABLE 4.2
IMPACTS OF ESDs' INCORPORATION ON PERFORMANCE OF VPP MODEL DEVELOPED USING IEEE RTS

<i>VPP performance indices</i>	<i>VPP model</i>	
	<i>Without ESDs</i>	<i>With ESDs</i>
MVPPE (MWh/year)	1.4125×10^3	8.6767×10^2
ERENU (MWh/year)	5.3408×10^2	4.1095×10^2
ESGD (MWh/year)	4.9789×10^5	4.9788×10^5
[WTG+PV/GT/ESD] (%)	[44.34/55.66/-]	[44.26/55.63/0.11]
ESGS (MWh/year)	4.7727×10^2	4.7732×10^2
[WTG+PV/GT/ESD] (%)	[48.37/51.63/-]	[48.36/51.62/0.02]

Fig. 4.9 IEEE RTS test case: (a) Breakdown of VPP's annual average DG outputs amongst end uses, and (b) Breakdown of share of energy sources in meeting VPP's internal network demand

4.4.2. Generation Adequacy Indices Incorporating Augmented VPP Model

Table 4.3 compares key system reliability indices LOLF, LOLE and LOEE [33] computed from the generation adequacy assessment of the RBTS after respectively incorporating the VPP models with (as developed in Section 4.3.2) and without (as developed in Chapter 3) ESDs into the RBTS. Similarly, Table 4.4 compares the values of key system reliability indices as computed for the IEEE RTS after incorporating the VPP models with and without ESDs into the RTS.

TABLE 4.3
IMPACTS OF ESDs' INCORPORATION ON GENERATING SYSTEM ADEQUACY INDICES COMPUTED FOR RBTS

<i>Generation adequacy indices</i>	<i>RBTS+VPP</i>	
	<i>Without ESDs</i>	<i>With ESDs</i>
LOLF (occurrences/year)	0.0488	0.0466
LOLE (hours/year)	0.1584	0.1526
LOEE (MWh/year)	1.2710	1.2203

TABLE 4.4
IMPACTS OF ESDs' INCORPORATION ON GENERATING SYSTEM ADEQUACY INDICES COMPUTED FOR RTS

<i>Generation adequacy indices</i>	<i>RTS+VPP</i>	
	<i>Without ESDs</i>	<i>With ESDs</i>
LOLF (occurrences/year)	1.3783	1.378
LOLE (hours/year)	6.1464	6.1458
LOEE (MWh/year)	7.4806×10^2	7.4801×10^2

These results quantify the impacts of the ESDs' integration with the VPP's generation portfolio on overall system reliability. As can be observed from Tables 4.3 and 4.4, the incorporation of ESDs produces a very nominal improvement in system reliability, which is consistent with the fact that only 10 MWh and 34 MWh of total rated ESD capacities are respectively added for the RBTS and RTS test cases, as against their corresponding annual peak loads of 185 MW and 2850 MW. Another important factor contributing to this is the generally low utilization efficiency of the modelled ESDs, as depicted in Figs. 4.5 and 4.8.

The simulations for obtaining the overall VPP model (including ESDs) and in turn using it for computing the generation adequacy indices (for both the RBTS and RTS test cases) were performed on a Windows desktop loaded with an Intel core i7 processor (3.4 GHz) and an 8 GB RAM. For obtaining the RTS results presented in Figs. 4.7 – 4.9 and in Tables 4.2 and 4.4, it took 3381 years simulated over a span of 2649 seconds to yield converged values. This is indicative of the general time requirements for performing the simulations as part of this chapter, and as such is considered acceptable keeping in mind that the main focus of this thesis work is on power system planning (which is a long-term issue).

4.4.3. Impacts of ESD Rated Capacities on Indices

A sensitivity study was conducted for investigating the impacts of changes in the ESD rated capacities ' $E_{R,s}$ ' on the VPP performance indices and the system reliability indices. For conducting these studies using the RBTS and the RTS test cases, the assumed rated capacities of the modelled ESDs (as mentioned in Section 4.4) for the respective systems were varied using the following multipliers: 0 (no ESDs), 0.5, 1 (corresponding to the results presented in Sections 4.4.1 and 4.4.2), 1.5 and 2. The locations and numbers of the modelled ESDs were kept the same as specified in Section 4.2 and shown in Figs. 4.1 and 4.2 for the respective test systems. All remaining parameters used for obtaining the results presented in this section are stated in Section 4.4.

Comparisons of the VPP performance and system reliability indices obtained for the RBTS (with RBTS Bus 4 distribution network) and the RTS (with IEEE 69-bus distribution network) test cases as a function of the ESD rated capacity are presented in Tables 4.5 and 4.6 respectively. An increase in the ESD rated capacity provides additional room to the batteries for storing energy, either from the excess VPP energy ' $P_{VPP,ij}$ ' in Stage II.A or using the DG curtailments in Stages II.A and II.C. This therefore produces a gradual and corresponding reduction in the MVPPE and ERENU values as shown in Tables 4.5 and 4.6. The variation of ESD rated capacities is found to have a minimal impact on the calculated ESGD and ESGS values in Tables 4.5 and 4.6.

Though the modest addition of ESD capacity does help in meeting some system energy deficit (as indicated by the slight improvements in the LOEE and LOLE values in Tables 4.5 and 4.6), the LOLF remains virtually unchanged over the range of ESD capacities modelled. This can be explained by taking a closer look at the adopted ESD operating policy. Since the only determining factor for operating the ESDs in discharging mode is whether $P_{VPP,ij} < 0$ (refer to Section 4.3.2.3), there are hours during the simulation process when the batteries undergo discharging even when the overall system is in the 'Success' state (i.e., total generation exceeds demand). This implies that the batteries do not contribute to system reliability improvement in such hours. Considering the high penetration of renewables in the VPP's DG portfolio and the low utilization efficiency of the batteries (as depicted in Figs. 4.5 and 4.8), there is a reasonable probability that for hours when the system encounters a 'Failure' state, the residual energy in the ESDs is already too low for them to be able to discharge and make a significant contribution to system reliability improvement. Additionally, there may be hours when the system is in a 'Failure' state but $P_{VPP,ij} \geq 0$. Since the adopted operating policy ensures that the surplus energy is used for charging the ESDs for such hours (instead of being used for reducing the system energy deficit), this furthermore limits the ESDs' contributions in improving system reliability. The overall impact of incorporating ESDs on the generation adequacy indices is therefore quite muted.

TABLE 4.5
COMPARISON OF INDICES OBTAINED USING RBTS AS A FUNCTION OF ESD RATED CAPACITY

<i>VPP performance indices</i>	<i>ESD rated capacity ‘E_{R,s}’ multiplier</i>				
	0	0.5	1	1.5	2
MVPPE (MWh/year)	6.4016 X 10 ³	5.6733 X 10 ³	5.0655 X 10 ³	4.5482 X 10 ³	4.1068 X 10 ³
ERENU (MWh/year)	195.3857	156.4135	130.66	113.7138	103.1543
ESGD (MWh/year)	1.5872 X 10 ⁵	1.586 X 10 ⁵	1.5851 X 10 ⁵	1.5842 X 10 ⁵	1.5835 X 10 ⁵
ESGS (MWh/year)	8.653	8.4152	8.416	8.4164	8.4167
<i>Generation adequacy indices</i>					
LOLF (occurrences/year)	0.0488	0.0467	0.0466	0.0466	0.0466
LOLE (hours/year)	0.1584	0.1527	0.1526	0.1525	0.1524
LOEE (MWh/year)	1.2710	1.2211	1.2203	1.2199	1.2196

TABLE 4.6
COMPARISON OF INDICES OBTAINED USING RTS AS A FUNCTION OF ESD RATED CAPACITY

<i>VPP performance indices</i>	<i>ESD rated capacity ‘E_{R,s}’ multiplier</i>				
	0	0.5	1	1.5	2
MVPPE (MWh/year)	1.4125 X 10 ³	1.1011 X 10 ³	8.6767 X 10 ²	6.9149 X 10 ²	5.5822 X 10 ²
ERENU (MWh/year)	5.3408 X 10 ²	4.6514 X 10 ²	4.1095 X 10 ²	3.6808 X 10 ²	3.3178 X 10 ²
ESGD (MWh/year)	4.9789 X 10 ⁵	4.9788 X 10 ⁵	4.9788 X 10 ⁵	4.9788 X 10 ⁵	4.9789 X 10 ⁵
ESGS (MWh/year)	4.7727 X 10 ²	4.7729 X 10 ²	4.7732 X 10 ²	4.7733 X 10 ²	4.7735 X 10 ²
<i>Generation adequacy indices</i>					
LOLF (occurrences/year)	1.3783	1.378	1.378	1.378	1.378
LOLE (hours/year)	6.1464	6.146	6.1458	6.1455	6.1452
LOEE (MWh/year)	7.4806 X 10 ²	7.4803 X 10 ²	7.4801 X 10 ²	7.4799 X 10 ²	7.4798 X 10 ²

4.4.4. Impacts of ESD Charging Periods on Indices

Another sensitivity study was conducted for investigating the impacts of changes in the ESD charging periods ‘T_{ch}’ on the VPP performance and system adequacy indices. The assumed charging periods of the modelled ESDs (as mentioned in Section 4.4) for both the RBTS and RTS test systems were varied in the following range: 1, 3, 5 (corresponding to the results presented in Sections 4.4.1 and 4.4.2), 7 and 9 hours. The locations and numbers of the modelled ESDs were kept the same as specified in Section 4.2 and shown in Figs. 4.1 and 4.2 for the respective test systems. All remaining parameters including ESD rated capacities used for obtaining the results presented in this section are stated in Section 4.4.

Tables 4.7 and 4.8 present comparisons of the VPP performance and system reliability indices obtained for the RBTS and RTS test systems respectively as a function of the ESD charging period. It can be observed from (4.1) that higher ‘T_{ch}’ values lead to a reduction in the maximum energy ‘E_{max,s}’ that ESD ‘s’ can consume or dispatch (assuming T_{ch} = T_d) over an hour. Reduced ‘E_{max,s}’ values put increasing limitations on the charging energy requirements from ESDs as computed using (4.4). Since part of the ESD charging energy requirements are supplied using the surplus VPP energy ‘P_{VPP,ij}’ (Stage II.A), this produces a corresponding increase in the MVPPE values shown in Tables 4.7 and 4.8. Reduced ‘E_{max,s}’

values also imply a corresponding decrease in the amount of dispatchable energy from ESDs as computed using (4.12). It is clear that too high (too low) ' T_{ch} ' values produce too low (too high) values of ' $E_{max,s}$ ', which in turn implies that the batteries undergo very slow (very fast) charging/discharging cycles. There therefore appears to be a particular charging period which produces an optimal charging and discharging rate for the batteries, such that the corresponding ERENU and system adequacy indices generated are the minimum. As observed from Tables 4.7 and 4.8, this optimal charging period equals 5 hours and 3 hours for the RBTS and RTS test cases respectively. A higher charging period not only reduces the usage of DG curtailments for charging the batteries (Stages II.A and II.C), but also puts increased constraints in the capabilities of the ESDs in meeting system energy deficit. This is indicated by the deteriorating ERENU, LOLE and LOEE values for higher ESD charging periods. Variations in the ' T_{ch} ' values do not significantly impact the calculated ESGD, ESGS and LOLF indices, as shown in Tables 4.7 and 4.8. The rather subdued impacts of the ESD charging periods on the generation adequacy indices can be attributed to several factors, e.g., the modest addition of ESD capacity with respect to system peak demand, the adopted ESD operating policy as well as the low utilization efficiency of the batteries. These factors are explained in greater detail in Section 4.4.3.

TABLE 4.7
COMPARISON OF INDICES OBTAINED USING RBTS AS A FUNCTION OF ESD CHARGING PERIOD

<i>VPP performance indices</i>	<i>ESD charging period 'T_{ch}' (hours)</i>				
	1	3	5	7	9
MVPPE (MWh/year)	4.911×10^3	4.9415×10^3	5.0655×10^3	5.2281×10^3	5.3916×10^3
ERENU (MWh/year)	157.2957	141.467	130.66	136.3347	144.7265
ESGD (MWh/year)	1.5846×10^5	1.5848×10^5	1.5851×10^5	1.5853×10^5	1.5856×10^5
ESGS (MWh/year)	8.4146	8.4155	8.416	8.4157	8.4154
<i>Generation adequacy indices</i>					
LOLF (occurrences/year)	0.0467	0.0466	0.0466	0.0466	0.0466
LOLE (hours/year)	0.1527	0.1526	0.1526	0.1527	0.1527
LOEE (MWh/year)	1.2217	1.2208	1.2203	1.2206	1.2209

TABLE 4.8
COMPARISON OF INDICES OBTAINED USING RTS AS A FUNCTION OF ESD CHARGING PERIOD

<i>VPP performance indices</i>	<i>ESD charging period 'T_{ch}' (hours)</i>				
	1	3	5	7	9
MVPPE (MWh/year)	7.9639×10^2	8.0886×10^2	8.6767×10^2	9.4715×10^2	1.0171×10^3
ERENU (MWh/year)	4.1045×10^2	4.0488×10^2	4.1095×10^2	4.2532×10^2	4.3946×10^2
ESGD (MWh/year)	4.9787×10^5	4.9788×10^5	4.9788×10^5	4.9789×10^5	4.9789×10^5
ESGS (MWh/year)	4.7732×10^2	4.7732×10^2	4.7732×10^2	4.7731×10^2	4.773×10^2
<i>Generation adequacy indices</i>					
LOLF (occurrences/year)	1.378	1.378	1.378	1.378	1.378
LOLE (hours/year)	6.1458	6.1455	6.1458	6.1458	6.1458
LOEE (MWh/year)	7.4801×10^2	7.48×10^2	7.4801×10^2	7.4802×10^2	7.4802×10^2

4.4.5. Impacts of Load Forecast Uncertainty on Indices

The VPP operating policy presented in Section 4.3.2.5 implicitly assumes that the total system demand is accurately forecast for each hour ‘i’ of simulation year ‘j’. In reality, however, there is an inherent uncertainty associated with these forecast values. The impacts of load forecast uncertainty on the VPP performance indices and the system reliability indices are investigated in detail in this section using both the RBTS and the RTS test cases.

Load forecast uncertainty is usually modelled using a normal distribution with a mean equal to the forecast peak load and a standard deviation equal to a given percentage of the forecast peak load [28, 37, 78]. Normally distributed random numbers therefore need to be generated in order to incorporate load forecast uncertainty into the simulation process. The effect of load forecast uncertainty is incorporated into the randomly varying hourly load model described in Section 3.3.2 using the following equation [78]:

$$P_{D,peak,j}^{unc} = P_{D,peak,j} + \sigma * Z_j \quad (4.30)$$

where ‘ $P_{D,peak,j}$ ’ and ‘ $P_{D,peak,j}^{unc}$ ’ (both in MW) respectively refer to the forecast value of the annual peak load for year ‘j’ and its corresponding value after incorporating the effect of load forecast uncertainty; ‘ σ ’ represents the standard deviation (a given value in %) of the forecast peak load; and ‘ Z_j ’ denotes a standard normal variable $\sim N(0,1)$.

The sequential algorithm of Section 4.3.4 is slightly modified for incorporating the effects of load forecast uncertainty into the overall simulation procedure. For each year ‘j’, a uniformly distributed random number between [0,1] is drawn, and the corresponding value of ‘ Z_j ’ is determined using the cumulative distribution function of a standard normal distribution. The modified annual peak load (incorporating uncertainty) for year ‘j’, ‘ $P_{D,peak,j}^{unc}$ ’, is then computed using (4.30). The hourly demands (incorporating uncertainty) for year ‘j’, ‘ $P_{D,ij}^{unc}$ ’, are then proportionally obtained with respect to the modified annual peak load ‘ $P_{D,peak,j}^{unc}$ ’ [78]. The sequential simulation algorithm essentially proceeds as illustrated in Fig. 4.3 after substituting the variable ‘ $P_{D,ij}$ ’ (representing the forecast values of the hourly system demand) with ‘ $P_{D,ij}^{unc}$ ’.

In order to study the impacts of load forecast uncertainty on the VPP performance indices and the system reliability indices, the parameter ‘ σ ’ is varied in the following range: 0%, 3%, 6%, 9% and 12%. The load forecast uncertainty is therefore characterized in this chapter using ‘ σ ’. All remaining parameters used for obtaining the results presented in this section are stated in Section 4.4. Comparisons of the VPP performance and system adequacy indices obtained for the RBTS and RTS test cases as a function of the load forecast uncertainty are presented in Tables 4.9 and 4.10 respectively.

Increased uncertainties in the hourly demands cause a corresponding rise in the amount of fluctuations encountered in the VPP output states (as represented by the decision variable ‘ $P_{0,ij}$ ’) over the course of the simulation. Over the long-term, this leads to a corresponding increase in the VPP’s annual average energy exports to the transmission grid, as quantified in Tables 4.9 and 4.10 using MVPPE. Increased uncertainties in the hourly demands also cause increased generation curtailments to be carried out from the VPP’s constituent DGs over the course of the simulation, thereby producing a corresponding rise in the computed ERENU values. As can also be observed from the tables, a rise in the load forecast uncertainty generally produces a corresponding gradual decline in the calculated ESGD values, though this trend is reversed when considering ESGS. As expected, all system reliability indices steadily deteriorate along with a corresponding increase in the load forecast uncertainty.

TABLE 4.9
COMPARISON OF INDICES OBTAINED USING RBTS AS A FUNCTION OF LOAD FORECAST UNCERTAINTY

<i>VPP performance indices</i>	<i>Standard deviation ‘σ’ (%) of forecast peak load</i>				
	0	3	6	9	12
MVPPE (MWh/year)	5.0655×10^3	5.1312×10^3	5.3315×10^3	5.674×10^3	6.1651×10^3
ERENU (MWh/year)	130.66	132.3883	136.6699	144.0171	154.6672
ESGD (MWh/year)	1.5851×10^5	1.5852×10^5	1.585×10^5	1.5848×10^5	1.5845×10^5
ESGS (MWh/year)	8.416	9.7162	13.5455	22.3924	41.7982
<i>Generation adequacy indices</i>					
LOLF (occurrences/year)	0.0466	0.0545	0.0763	0.1282	0.2443
LOLE (hours/year)	0.1526	0.179	0.2633	0.4611	0.9176
LOEE (MWh/year)	1.2203	1.5395	2.3822	4.5012	9.702

TABLE 4.10
COMPARISON OF INDICES OBTAINED USING RTS AS A FUNCTION OF LOAD FORECAST UNCERTAINTY

<i>VPP performance indices</i>	<i>Standard deviation ‘σ’ (%) of forecast peak load</i>				
	0	3	6	9	12
MVPPE (MWh/year)	8.6767×10^2	9.1201×10^2	1.0553×10^3	1.3281×10^3	1.7784×10^3
ERENU (MWh/year)	4.1095×10^2	4.1484×10^2	4.1821×10^2	4.242×10^2	4.3296×10^2
ESGD (MWh/year)	4.9788×10^5	4.9785×10^5	4.976×10^5	4.9707×10^5	4.9615×10^5
ESGS (MWh/year)	4.7732×10^2	5.3516×10^2	7.7687×10^2	1.2858×10^3	2.1688×10^3
<i>Generation adequacy indices</i>					
LOLF (occurrences/year)	1.378	1.5302	2.1415	3.3913	5.3017
LOLE (hours/year)	6.1458	6.9716	10.1657	16.9314	29.029
LOEE (MWh/year)	7.4801×10^2	8.8282×10^2	1.3893×10^3	2.5515×10^3	4.979×10^3

4.5. Conclusions

A generic methodology for investigating the impacts of incorporating ESDs into a VPP model and subsequently using it for performing generating system adequacy studies is presented in this chapter. A linearized network flow based multi-stage optimization formulation is proposed for developing the overall VPP model incorporating DGs, ESDs and loads along with network-specific information like

topology and constraints. The ESDs are assumed to be charged or dispatched using a fair energy allocation based operating policy. Modified formulations of VPP performance indices MVPPE, ERENU, ESGS and ESGD are presented. Several sensitivity studies are conducted for analysing the impacts of the ESDs' incorporation as well as of variations in ESD parameters and load forecast uncertainty on the VPP performance and system adequacy indices.

It should be noted that the results presented in Section 4.4 are dependent on numerous factors, e.g., the adopted VPP operating policy, ESD charging/discharging strategy as well as the simulation data used. The overall methodology proposed in this chapter is, however, generic, and can serve as a helpful tool for VPP aggregators as well as the system operator for conducting a thorough analysis regarding the VPP performance and system adequacy benefits expected from installing ESDs with respect to the preferred VPP operating policy and the available data for the system under consideration.

CHAPTER 5

BULK POWER SYSTEM ADEQUACY ASSESSMENT INCORPORATING VPPs

This chapter presents a systematic procedure for assessing bulk power system adequacy incorporating the augmented VPP model developed in Chapter 4. A linearized DC load flow based OPF formulation is proposed for performing transmission network contingency analysis. The OPF problem minimizes the total load curtailment and generation costs for the system, while also enabling priority dispatch of the VPP output (if available) into the external grid. The VPP performance indices (MVPPE, ERENU, ESGS and ESGD) are suitably modified for highlighting the impacts of transmission grid constraints and contingencies on the VPP profile characteristics. Key reliability indices computed at the system as well as at individual transmission bus levels are presented, with the VPP assumed to be connected at different transmission buses. Impacts of changes in factors such as the VPP's point of connection to the transmission grid as well as the failure and repair rates of transmission lines on the VPP's performance metrics are also presented. The bulk power system adequacy studies incorporating the augmented VPP model are carried out on the RTS in conjunction with the IEEE 69-bus distribution network using a sequential simulation algorithm.

5.1. Introduction

5.1.1. Literature Review

Several publications which model the aggregated impact of DERs on power system reliability have been reviewed [74, 79–84]. Detailed analytical expressions are introduced in [79] for quantifying the reliability improvements brought about by the incorporation of microgrids (including DERs) in a given distribution network. Impacts of including distribution network feeder constraints as well as variations in the microgrid generation and load ratio on the quantum of the improvements obtained are also studied in [79]. A pseudo-sequential Monte Carlo simulation based active distribution network reliability evaluation is carried out in [80], where a suitable information and communication technology framework is proposed for performing active management of the distribution network such that the reliability benefits obtained are the same as those available from a traditional network upgradation measure. The role of DGs on the distribution side in reducing transmission system risk is investigated in [81], wherein the concept of available supply capacity is used for maintaining distribution network security after the occurrence of outages. Reference [82] employs probabilistic OPF techniques for investigating the impacts of incorporating demand response programs (DRP) in a multi-objective transmission expansion planning

problem. The loads participating in DRPs are modelled in [82] as VPPs, and different cost components like investment costs for adding new lines, transmission congestion and risk costs as well as incentive costs for participating in DRPs are considered as competing objectives of the planning problem. A few DRPs are modelled and the optimal program which offers the highest return on investment to the system operator is determined. Several DGs and electric vehicles are modelled in [83] as a VPP at the transmission grid interface, and a security constrained unit commitment formulation is presented for optimally dispatching grid-connected conventional generation along with the VPP. The multi-objective optimization formulation presented in [83] aims to minimize the total power generation, pollution and unit start-up and shut-down costs, while satisfying relevant system security and operational constraints. A bi-objective OPF formulation with two competing objective functions is presented in [84], where the minimization of the joint energy and reserve market clearing cost and maximization of the system loadability limit are modelled as the economic and security objectives (respectively) of the optimization problem. Price responsive curtailable demands are modelled in [84] as VPPs (referred to as ‘microgrid aggregators’ in the paper) at the transmission grid interface, and they are assumed to submit multi-block load curtailment offers to the ISO similar to energy offers submitted by grid-connected conventional generation.

5.1.2. Motivations

The aggregated energy production capabilities of the VPP’s constituent DERs, which can be used for meeting both internal network as well as external grid demands, are not adequately captured from the distribution network reliability evaluations carried out in [79–80]. Though [74] performs transmission network contingency analysis and models the participation of ESDs in supplying energy to the external grid during load curtailment events in the bulk power system, neither is the amount of energy exported explicitly quantified nor are the DGs incorporated into the energy export policy. Reference [81] presents a methodology for performing transmission system risk assessment including DGs on the distribution side; however, the DGs are employed solely for the purpose of mitigating possible load curtailments in their own distribution network, i.e., their aggregated capability to export surplus energy to the external grid is not modelled. References [82–84] present bulk power system adequacy assessment frameworks incorporating aggregated representations of demand side DERs at the transmission grid interface, but the distribution networks are modelled as lumped components and all associated topology and constraint related information are ignored. Moreover, the reviewed literature does not indicate any research output which can quantify different aspects of the VPP’s performance while considering topology and constraint related information of both transmission and distribution networks. The deficiencies in the reviewed literature are partially addressed through the studies presented in Chapters 3 and 4, however, the impacts

of transmission grid constraints and contingencies are not modelled as part of the generation adequacy assessments performed in those chapters. This chapter bridges the gaps in the reviewed literature as well as in the work presented in the previous chapters by proposing a general methodology for assessing bulk power system adequacy incorporating the augmented VPP model developed in Chapter 4 [32].

5.1.3. Contributions

The primary contributions of this chapter are as follows: 1) A linearized DC load flow based OPF formulation is proposed for performing transmission network contingency analysis. The OPF problem minimizes the total load curtailment and generation costs for the system, while also enabling priority dispatch of the VPP output (if available) into the external grid. 2) The VPP performance indices – MVPPE, ERENU, ESGS and ESGD – are suitably modified for highlighting the impacts of transmission grid constraints and contingencies on the VPP profile characteristics. 3) Key reliability indices computed at the system as well as at individual transmission bus levels are presented, with the VPP assumed to be connected at different transmission buses. Impacts of changes in factors such as the VPP's point of connection to the transmission grid as well as the failure and repair rates of transmission lines on the VPP's performance metrics are also investigated.

5.2. Proposed Bulk Power System Adequacy Assessment Methodology

5.2.1. Overview of Distribution Network Used for Modelling VPP

The overall methodology presented in this chapter is tested using the IEEE RTS [25], with the IEEE 69-bus distribution network [27] being used for modelling the VPP as shown in the layout of Fig. 4.2. Several DGs and ESDs are assumed to be integrated with the network, with their locations, numbers and types being mentioned in Sections 3.2 and 4.2 respectively. The VPP model corresponding to the IEEE 69-bus distribution network is characterized by an annual peak load of 181 MW.

5.2.2. Proposed DC Load Flow Based OPF Formulation Incorporating Augmented VPP Model

Bulk power system contingency analysis algorithms essentially employ OPF formulations which may be based on linearized or non-linear load flow models depending on the target of the optimization as well as constraints considered [28]. The linearized DC load flow based OPF formulation designed as part of the bulk power system adequacy assessment procedure presented in this chapter is expressed below. It should be noted that since the VPP performance and system adequacy indices computed throughout this thesis are functions of active power only, a simplified DC load flow based approach is adopted. Besides, considering the computational burden associated with the sequential simulations performed in this research work, the time requirements for executing the DC load flow based formulation are much lesser

as compared to a full-scale AC power flow based contingency analysis approach. However, if a particular study necessitates the investigation of the impacts of the VPP's injections on network security constraints (e.g. bus voltages) as well as losses, the OPF formulation (5.1) – (5.7) needs to be reformulated using more detailed AC power flow based equations as suggested in [28].

The objective function (5.1) consists of two parts – while the first summation aims to minimize the load curtailment costs (i.e., if curtailments are inevitable) associated with the system load buses, the second summation minimizes the system generation cost by dispatching grid-connected generating units according to a pre-specified loading order. The perceived financial damage associated with curtailed energy has been quantified using the Interrupted Energy Assessment Rate 'IEAR' (\$/kWh) index in several publications [28, 85–87]. The load curtailment policy adopted in this chapter is to rank the system load buses according to their associated IEAR values. Buses with a low IEAR are assumed to have their loads curtailed first before shedding loads from more critical buses (e.g., industrial zones) associated with high IEAR values [86]. The rationale behind doing this is to minimize the associated load curtailment costs in the event that energy interruption is inevitable [87]. Similarly, the generation dispatch philosophy adopted in this chapter is to prioritize the export of energy from the VPP to the transmission grid, as long as it's available for dispatch. This is enforced by assigning the lowest value for the incremental generation cost (\$/MWh) associated with energy dispatched from the VPP. Other transmission grid-connected generating units of the original test system are assumed to be dispatched according to the economic loading order (units with lower incremental generation costs are dispatched first followed by those having higher production costs) presented in [88]. The adopted generation dispatch philosophy therefore minimizes the system generation cost, while also enabling priority dispatch of the VPP output (if available) into the external grid.

Objective function:

$$\min \{ \sum (\lambda_b * C_{b,ij}) + \sum (\lambda_g * P_{dis,g,ij}) \}, \forall b \in B_D, \forall g \in G \quad (5.1)$$

Constraints:

$$\sum P_{dis,g,ij} + \sum C_{b,ij} = \sum P_{D,b,ij}, \forall b \in B_D, \forall g \in G \quad (5.2)$$

$$P_{g,min} \leq P_{dis,g,ij} \leq P_{g,max,ij}, \forall g \in G \quad (5.3)$$

$$0 \leq C_{b,ij} \leq P_{D,b,ij}, \forall b \in B_D \quad (5.4)$$

$$P_{t,ij} = \sum_{b=1}^{N_b-1} A_{t,b,ij} * [\sum P_{dis,g,b,ij} + C_{b,ij} - P_{D,b,ij}], \forall t \in T, \forall b \in B, b \neq slack \quad (5.5)$$

$$abs(P_{t,ij}) \leq P_{t,max}, \forall t \in T \quad (5.6)$$

Decision variable:

$$P_{inj,VPP,ij} = \begin{cases} P_{dis,VPP,ij}, P_{0,ij} \geq 0 \\ P_{0,ij} + C_{VPP,ij}, P_{0,ij} < 0 \end{cases} \quad (5.7)$$

where ‘B’, ‘B_D’, ‘T’ and ‘G’ respectively represent the set of all buses, load buses, transmission lines and grid-connected generators in the transmission network under consideration; the terms ‘ λ_b ’ and ‘ λ_g ’ denote the IEAR (\$/kWh) value and the incremental generation cost (\$/MWh) associated with load bus ‘b’ and generating unit ‘g’ respectively; ‘C_{b,ij}’ and ‘P_{dis,g,ij}’ (MW) represent the optimal curtailment to be carried out and the optimal dispatch from load bus ‘b’ and generating unit ‘g’ respectively; ‘ $\Sigma P_{dis,g,ij}$ ’, ‘ $\Sigma C_{b,ij}$ ’ and ‘ $\Sigma P_{D,b,ij}$ ’ (MW) respectively represent the total generation dispatch, the total curtailments and the total demand associated with the system under consideration; ‘P_{g,min}’ and ‘P_{g,max,ij}’ (MW) refer to the minimum and maximum generation limits associated with the generation dispatch from unit ‘g’; ‘P_{D,b,ij}’ (MW) refers to the demand at load bus ‘b’; variables ‘P_{t,ij}’ and ‘P_{t,max}’ (MW) respectively represent the power flow through transmission line ‘t’ along with its corresponding maximum limit; [A]_{ij} is the relationship matrix between the line flows and power injections associated with the transmission network under consideration for hour ‘i’ of simulation year ‘j’; ‘ $\Sigma P_{dis,g,b,ij}$ ’ (MW) and ‘N_b’ respectively represent the total dispatch from generators connected to bus ‘b’ and the total number of buses in the transmission network under consideration; and *decision variable* ‘P_{inj,VPP,ij}’ (MW) denotes the optimal power injection at the VPP’s interface with the transmission grid (denoted by node 0 in Fig. 4.2). A positive ‘P_{inj,VPP,ij}’ signifies the optimal energy that the VPP aggregator exports to the external grid after satisfying internal network demands and constraints (as presented in Section 4.3.2.2), transmission grid constraints and contingencies as well as the generation dispatch philosophy adopted in this chapter. Similarly, a negative ‘P_{inj,VPP,ij}’ denotes the optimal energy that the VPP aggregator imports from the external grid for meeting the energy deficit in its internal network, after optimally dispatching its own DGs and ESDs (as carried out in Section 4.3.2.3) while also satisfying relevant transmission grid constraints and contingencies as well as the load curtailment policy adopted in this chapter. Line flows ‘P_{t,ij}’ can be computed using the DC load flow based equation (5.5) where ‘A_{t,b,ij}’ refers to individual elements from row ‘t’ of matrix [A]_{ij}. [A]_{ij} is a function of line admittances as well as the transmission network topology, and is calculated using the technique presented in [28]. The terms within the square brackets in (5.5) signify the total power injection at bus ‘b’. Parameters ‘P_{dis,VPP,ij}’ and ‘C_{VPP,ij}’ in (5.7) are specific representations of variables ‘P_{dis,g,ij}’ and ‘C_{b,ij}’, as computed for the VPP for hours when P_{0,ij} ≥ 0 and P_{0,ij} < 0 respectively. ‘P_{0,ij}’ is as obtained using (4.9) or (4.17).

Since increasing generation dispatches automatically leads to reduction in load curtailments (and hence the associated curtailment costs) and the set of chosen ‘ λ_b ’ values are greater in magnitude than the set of ‘ λ_g ’ values, the two parts of objective function (5.1) are actually complementary to each other, and maximizing the second (at minimum cost) while minimizing the first leads to overall minimization of the objective function as well as realization of the load curtailment and generation dispatch philosophies adopted in this chapter. While (5.2) enforces power conservation (supply-demand balance) for the overall

system under consideration, constraints (5.3), (5.4) and (5.6) respectively ensure that the generation dispatches, load curtailments and line flows stay within appropriate limits. The OPF formulation presented in (5.1) – (5.7) is executed using the ‘*linprog*’ function of the MATLAB optimization toolbox [63] in conjunction with the MATPOWER simulation package [89]. The optimization formulation has been modified from [28] in order to incorporate priority dispatching of the VPP output into the objective function definition.

5.2.3. Adopted Operating Policy for Modelling VPP’s Interactions with ISO

The adopted VPP operating policy presented in Section 4.3.2.5 is extended in this chapter for explicitly modelling the VPP’s interactions with the ISO. For every hour ‘*i*’ when $P_{0,ij} \geq 0$ (as computed in Section 4.3.2.2), the VPP aggregator appears as an equivalent generating unit to the ISO and offers this surplus energy for being dispatched on a priority basis for meeting as much of the external grid demand as possible. The ISO executes the OPF formulation (5.1) – (5.7) and obtains the optimal dispatch schedule for all grid-connected generating units (including the VPP). In the event that the whole of the VPP’s surplus energy ‘ $P_{0,ij}$ ’ is unable to be dispatched owing to transmission grid constraints and contingencies, the VPP output is curtailed by first reducing the generation from the conventional sources, followed by the renewable DGs until overall energy balance for the VPP is achieved. Similarly, for hours when $P_{0,ij} < 0$ (as computed in Section 4.3.2.3), the VPP aggregator appears as an equivalent load to the ISO, which in turn obtains the optimal curtailments (if at all necessary) at the system load buses (including at the VPP’s transmission grid interface) after executing the optimization formulation (5.1) – (5.7). It may therefore be noted that the following inequalities exist: $0 \leq P_{inj,VPP,ij} \leq P_{0,ij}$ and $P_{0,ij} \leq P_{inj,VPP,ij} \leq 0$ for hours when $P_{0,ij} \geq 0$ and $P_{0,ij} < 0$ respectively.

On similar lines to the rationale provided in Section 3.3.4, assigning the lowest incremental generation cost (or conversely, the highest dispatch priority) for the VPP’s energy dispatches into the external grid for hours when $P_{0,ij} \geq 0$ implies that the VPP aggregator is able to offer this excess energy ($P_{0,ij}$) either at a favourable price or in a favourable regulatory setting (perhaps with help from local authorities in the form of guaranteed feed-in tariffs and/or special market premiums as offered by some European Union countries [5, 7–8, 83]) to the ISO. The adopted VPP operating policy also encourages the growth of renewable DGs in the VPP’s generation portfolio by carrying out maximum possible curtailments from the conventional generators before reducing the dispatch from the renewable source based units. Finally, as discussed in Sections 3.3.4 and 4.3.2.5, the operating policy implicitly assumes that the sizing, siting and penetration levels of the modelled DERs in the VPP’s internal network along with the assigned generation dispatch priority order while performing transmission network contingency analysis do not cause any security constraint violations in the system under consideration. These

assumptions are routinely employed while performing long-term system adequacy studies at HLII [28, 74, 81, 83]. Readers should, however, note that the OPF formulation (5.1) – (5.7) along with the accompanying load curtailment, generation dispatch and VPP operating policies adopted in this chapter are generic in nature and can be easily substituted by appropriate alternatives as per the requirements of a given study.

5.2.4. Quantification of VPP's Performance for HLII Studies

Several indices were defined in Sections 3.3.5 and 4.3.3 for quantifying different aspects of the VPP's performance. The index formulations presented in the previous chapters were developed keeping in mind the topology and constraints along with the presence of DGs, ESDs and loads in the VPP's internal distribution network. These indices are suitably modified in this section for investigating the impacts of transmission grid constraints and contingencies on the performance of the augmented VPP model developed in Chapter 4. The definitions along with the expressions for the reformulated indices are presented below.

The reformulated MVPPE (MWh/year) pertaining to the bulk power system adequacy assessment procedure proposed in this chapter quantifies the expected amount of energy that the VPP exports to the transmission grid in a year after satisfying internal network demands and constraints, while also taking into consideration the impacts of transmission grid constraints and contingencies. The index is formulated as follows:

$$MVPPE = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} \max(0, P_{inj,VPP,ij}) \right) / N_y \quad (5.8)$$

where ' $P_{inj,VPP,ij}$ ' is as obtained using (5.7).

The reformulated ERENU (MWh/year) pertaining to the bulk power system adequacy assessment procedure proposed in this chapter quantifies the expected amount of energy from renewable DGs that needs to be curtailed every year either due to the VPP's internal network constraints or owing to transmission grid constraints and contingencies. The index is formulated as follows:

$$ERENU = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} \left\{ \left[\sum C_{k,ij}^r \right] + \left[\max(0, P_{0,ij} - P_{inj,VPP,ij} - (\sum G_{k,max,ij}^c - \sum C_{k,ij}^c)) \right] \right\} \right) / N_y \quad (5.9)$$

where ' $\sum C_{k,ij}^r$ ' is as obtained using (4.2) or (4.18); ' $P_{0,ij}$ ' is as obtained using (4.9) or (4.17); ' $P_{inj,VPP,ij}$ ' is as obtained using (5.7); ' $\sum C_{k,ij}^c$ ' is as obtained using (3.1); and ' $\sum G_{k,max,ij}^c$ ' (MW) is an aggregated representation of ' $G_{k,max,ij}$ ' for all conventional DGs modelled in the distribution network test bed under consideration. Note that the expressions within the first and second pair of square brackets in (5.9) are

respectively used for quantifying the contributions of the VPP's internal network constraints and of the transmission grid constraints and contingencies in the final computed ERENU value.

The reformulated ESGD (MWh/year) quantifies the expected amount of demand per year that would have otherwise been met by the original system generation but is now supplied by the VPP, while taking into consideration the impacts of transmission grid constraints and contingencies. Finally, the reformulated ESGS (MWh/year) is used for computing the expected amount of demand per year that would have otherwise remained unsatisfied either due to deficiency in the original system generation or owing to transmission grid constraints and contingencies (or both), but is now supplied by the VPP. The formulations of these indices, as they pertain to the bulk power system adequacy assessment procedure proposed in this chapter, are as follows:

$$ESGS_{ij} = EENS_{orig,ij} - EENS_{VPP,ij} \quad (5.10)$$

$$ESGD_{ij} = G_{VPP,ij} - ESGS_{ij} \quad (5.11)$$

$$X = \frac{\left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} X_{ij} \right)}{N_y}, X = ESGS \text{ or } ESGD \quad (5.12)$$

where 'EENS_{orig,ij}' and 'EENS_{VPP,ij}' (MWh) respectively refer to the EENS values for the original test system and the system after the VPP's incorporation; and 'G_{VPP,ij}' (MWh) represents the total energy injections of the VPP towards meeting system demand for hour 'i' of simulation year 'j'. 'EENS_{orig,ij}' and 'EENS_{VPP,ij}' are numerically equal to $\sum_{b \in B_D} C_{b,ij}$, as obtained for the respective systems (with and without the VPP) using the OPF formulation (5.1) – (5.6). 'G_{VPP,ij}' is calculated as follows:

$$G_{VPP,ij} = \begin{cases} P_{inj,VPP,ij} + \sum_{n \in N} D_{n,ij}, & P_{0,ij} \geq 0 \\ P_{0,ij} + \sum_{n \in N} D_{n,ij}, & P_{0,ij} < 0 \end{cases} \quad (5.13)$$

5.2.5. Bulk Power System Adequacy Assessment Algorithm Incorporating Augmented VPP Model

The flowchart of the Monte Carlo sequential simulation algorithm [28], used for performing the bulk power system adequacy studies in this chapter incorporating the augmented VPP model from Chapter 4, is presented in Fig. 5.1. Failures/repairs are simulated for the following components: the VPP's constituent DGs, the original system generating units as well as transmission lines. Component failures are represented using a two-state (Up/Down) model and ESDs are assumed to be completely reliable. The tasks to be executed for incorporating the augmented VPP model into the bulk power system adequacy studies conducted in this chapter are contained within the dashed rectangle in Fig. 5.1.

Fig. 5.1 Flowchart of Monte Carlo sequential algorithm used for performing bulk power system adequacy studies

5.3. Analysis of Results

This section presents the results obtained from the bulk power system adequacy studies conducted in this chapter incorporating the augmented VPP model developed in Chapter 4. The overall methodology proposed in this chapter is tested using the IEEE RTS [25], with the IEEE 69-bus distribution network [27] being used for modelling the VPP. Several DGs and ESDs are assumed to be integrated with the network, with relevant details of their modelling provided in Section 4.3.1. The assumed rated capacities of the DGs and ESDs are stated in Sections 3.4.1 and 4.4 respectively.

Other specifications regarding the failure/repair rate data and characteristic parameter values for the DGs and ESDs, the system load profile as well as the ARMA models used for predicting hourly wind speed/solar irradiance values are presented in Section 4.4. Values for ' λ_b ' and ' λ_g ' to be assigned in (5.1) are obtained from [85] and [88] respectively. Unless otherwise mentioned, the VPP is assumed to be connected to Bus 19 of the RTS.

5.3.1. Impacts of Transmission Grid Constraints and Contingencies on VPP's Performance

A comparison of the VPP performance indices obtained at HLI and HLII for the RTS test case is presented in Table 5.1. It can generally be expected that the performance indices calculated as part of a bulk power system adequacy assessment procedure would be worse off than their counterparts obtained using a generation adequacy assessment algorithm owing to the incorporation of transmission grid constraints and contingencies. The data presented in Table 5.1, however, shows that the VPP performance metrics (MVPPE, ERENU and ESGD+ESGS) generated using the HLI and HLII adequacy assessment methodologies are virtually the same.

TABLE 5.1
COMPARISON OF PERFORMANCE INDICES OBTAINED AT HLI AND HLII (VPP MODELLED AT BUS 19)

<i>VPP performance indices</i>	<i>Hierarchical level</i>	
	<i>HLI</i>	<i>HLII</i>
MVPPE (MWh/year)	8.6767×10^2	8.6766×10^2
ERENU (MWh/year)	4.1095×10^2	4.1096×10^2
ESGD (MWh/year)	4.9788×10^5	4.9791×10^5
ESGS (MWh/year)	4.7732×10^2	4.4861×10^2

The findings from Table 5.1 can be attributed to the location of Bus 19 in the RTS transmission network. Since Bus 19 is connected to the rest of the system using three transmission lines, the probability of combined failures of all three lines is almost negligible. This implies that there is almost always at least one transmission line connected to Bus 19 which has enough capacity to carry the excess energy from the VPP (if available). This, coupled with the fact that the RTS is characterized by a strong transmission network [90] and that the adopted operating policy prioritizes the export of energy from the VPP to the

transmission grid, ensures that the maximum VPP output available for export ' $P_{0,ij}$ ' is usually equal to the actual power dispatched ' $P_{inj,VPP,ij}$ '. The incorporation of transmission grid constraints and contingencies thus does not have any detrimental effect on the computed VPP performance indices at HLII as compared to their HLI counterparts. This can also be numerically verified by substituting ' $P_{inj,VPP,ij}$ ' by ' $P_{0,ij}$ ' in (5.8) – (5.13), and comparing the resultant formulations with the corresponding indices presented in (4.21) – (4.29) as part of the generation adequacy assessment methodology proposed in Chapter 4.

5.3.2. Bulk Power System Adequacy Indices Incorporating Augmented VPP Model

Bulk power system adequacy indices EFLC, EDLC and EENS [33] computed for the original RTS were compared with the corresponding values generated after incorporating the augmented VPP model from Chapter 4 at Bus 19 of the RTS. The results of the comparison are shown in Table 5.2.

TABLE 5.2
COMPARISON OF ADEQUACY INDICES OBTAINED AT HLII (VPP MODELLED AT BUS 19)

HLII adequacy indices	EFLC (occurrences/year)		EDLC (hours/year)		EENS (MWh/year)	
	Original RTS	RTS + VPP	Original RTS	RTS + VPP	Original RTS	RTS + VPP
Bulk System	2.1211	1.4674	10.5589	6.9357	1.3834×10^3	934.8185
Bus 1	0	0	0	0	0	0
Bus 2	0	0	0	0	0	0
Bus 3	0	0	0	0	0	0
Bus 4	1.4286×10^{-3}	3.7143×10^{-3}	0.006	0.01	0.2953	0.4234
Bus 5	5.7143×10^{-4}	0	0.002	0	0.0762	0
Bus 6	5.7143×10^{-4}	5.7143×10^{-4}	0.0111	4.857×10^{-3}	0.8927	0.4836
Bus 7	5.7143×10^{-4}	8.5714×10^{-4}	2.2857×10^{-3}	2.571×10^{-3}	0.0174	0.0396
Bus 8	1.106	0.7949	5.3026	3.5934	491.7981	336.7502
Bus 9	0	0	0	0	0	0
Bus 10	0.0737	0.1077	0.2986	0.4691	41.4797	39.18
Bus 13	0	0	0	0	0	0
Bus 14	1.1429×10^{-3}	1.4286×10^{-3}	3.7143×10^{-3}	3.143×10^{-3}	0.3945	0.1713
Bus 15	0	0	0	0	0	0
Bus 16	2.1186	1.4657	10.5389	6.928	708.1097	480.017
Bus 18	0	0	0	0	0	0
Bus 19	0.3257	0.244	1.448	1.066	138.9848	73.9857
Bus 20	0.01	0.0211	0.0294	0.0837	1.3791	3.7678

The data in Table 5.2 essentially quantifies the impacts of the VPP's incorporation on reliability at the system as well as at individual transmission bus levels. The loads curtailed at individual buses are in line with the corresponding ranks assigned to them as part of the curtailment philosophy adopted in this

chapter. The incorporation of the VPP generally leads to reliability improvements for the overall system as well as at individual buses, with the system EFLC, EDLC and EENS values being reduced to 69.18%, 65.69% and 67.57% respectively of their original counterparts.

5.3.3. Impacts of VPP's Location on Indices

Two sensitivity studies were conducted for investigating the impacts of changes in the VPP's point of connection to the transmission grid on the VPP performance indices and the system reliability indices. The first study was conducted with the VPP assumed to be located at Bus 10 of the RTS (instead of Bus 19). The peak loads associated with Buses 10 and 19 were swapped for this case study, while keeping all remaining transmission grid and VPP parameters the same as those used for obtaining the results in Sections 5.3.1 and 5.3.2. The VPP performance and bulk power system adequacy indices obtained for this sensitivity study are presented in Tables 5.3 and 5.4 respectively.

TABLE 5.3
COMPARISON OF PERFORMANCE INDICES OBTAINED AT HLI AND HLII (VPP MODELLED AT BUS 10)

<i>VPP performance indices</i>	<i>Hierarchical level</i>	
	<i>HLI</i>	<i>HLII</i>
MVPPE (MWh/year)	8.6767×10^2	8.6767×10^2
ERENU (MWh/year)	4.1095×10^2	4.1096×10^2
ESGD (MWh/year)	4.9788×10^5	4.9791×10^5
ESGS (MWh/year)	4.7732×10^2	4.4861×10^2

It can be observed from Table 5.3 that the VPP performance metrics (MVPPE, ERENU and ESGD+ESGS) generated using the HLI and HLII adequacy assessment methodologies are once again virtually the same. Bus 10, like Bus 19, is strongly connected to the rest of the RTS (three transmission lines and two transformer links), and the probability of combined failures of all these components is almost negligible. Similar to the discussions presented in Section 5.3.1, the incorporation of transmission grid constraints and contingencies into this sensitivity study therefore does not have any detrimental effect on the VPP performance indices at HLII as compared to their HLI counterparts.

The bulk power system adequacy indices (Table 5.4) obtained with the VPP connected to Bus 10 are mostly identical to those presented in Table 5.2 with the VPP assumed to be located at Bus 19. The RTS's strong transmission grid coupled with the fact that the VPP can inject all of its surplus energy to the external grid irrespective of its assumed locations ensures that the reliability of the system and most individual buses are the same for the two cases. There are, however, some differences in the indices associated with Buses 10 and 19. With the VPP assumed to be located at Bus 10, the reliability benefits obtained at that bus are greater than those obtained when the VPP was connected to Bus 19. For example, the Bus 10 EENS in Table 5.4 with the VPP incorporated is found to be only 42.48% of its corresponding

value in Table 5.2. Similarly, the relocation of the VPP from Bus 19 to Bus 10 produces some deterioration in the indices associated with the former. As compared to a reduction of 46.77% in the Bus 19 EENS value (with and without VPP) in Table 5.2, the corresponding reduction obtained in Table 5.4 is only 32.22%.

TABLE 5.4
COMPARISON OF ADEQUACY INDICES OBTAINED AT HLII (VPP MODELLED AT BUS 10)

HLII adequacy indices	EFLC (occurrences/year)		EDLC (hours/year)		EENS (MWh/year)	
	Original RTS	RTS + VPP	Original RTS	RTS + VPP	Original RTS	RTS + VPP
Bulk System	2.1211	1.4674	10.5589	6.9357	1.3834 $\times 10^3$	934.8188
Bus 1	0	0	0	0	0	0
Bus 2	0	0	0	0	0	0
Bus 3	0	0	0	0	0	0
Bus 4	1.4286 $\times 10^{-3}$	3.7143 $\times 10^{-3}$	0.006	0.01	0.2953	0.4234
Bus 5	5.7143 $\times 10^{-4}$	0	0.002	0	0.0762	0
Bus 6	5.7143 $\times 10^{-4}$	5.7143 $\times 10^{-4}$	0.0111	4.857 $\times 10^{-3}$	0.8927	0.4836
Bus 7	5.7143 $\times 10^{-4}$	8.5714 $\times 10^{-4}$	2.2857 $\times 10^{-3}$	2.571 $\times 10^{-3}$	0.0174	0.0396
Bus 8	1.106	0.7949	5.3026	3.5937	491.7979	336.7504
Bus 9	0	0	0	0	0	0
Bus 10	0.0617	0.0557	0.2469	0.2357	38.0514	16.6438
Bus 13	0	0	0	0	0	0
Bus 14	1.1429 $\times 10^{-3}$	1.4286 $\times 10^{-3}$	3.7143 $\times 10^{-3}$	3.143 $\times 10^{-3}$	0.3945	0.1713
Bus 15	0	0	0	0	0	0
Bus 16	2.1186	1.4657	10.5389	6.928	708.1097	480.0171
Bus 18	0	0	0	0	0	0
Bus 19	0.3257	0.244	1.448	1.066	142.4133	96.5219
Bus 20	0.01	0.0211	0.0294	0.0837	1.3791	3.7678

It is evident from the above discussions that had the VPP been modelled at a more remote bus with less number of transmission lines connecting it to the rest of the system, the VPP's performance metrics computed at HLII would have been more adversely affected with respect to their HLI counterparts. To test this, a second sensitivity study was conducted with the VPP assumed to be located at Bus 7 of the RTS (instead of Bus 19), which is connected to the rest of the system with only one transmission line (line 7–8). This implies that when transmission network contingencies are incorporated into the reliability evaluation procedure, the modelled VPP would be isolated from the rest of the system every time an outage occurs on that line. This in turn would have an overall adverse impact on the VPP performance metrics computed using HLII techniques as compared to their HLI counterparts, as

quantified in Table 5.5. The following modifications were incorporated into the RTS transmission network for obtaining these results. The peak loads associated with Buses 7 and 19 were swapped, the maximum flow limit associated with line 7–8 was increased from 175 MW to 230 MW, and the failure rate and mean time to repair (MTTR) values for this line were increased by 5 times. Remaining transmission grid and VPP parameters were kept the same as those used for obtaining the results in Sections 5.3.1 and 5.3.2. Considering the fact that the original peak load values associated with Buses 7 and 19 are 125 MW and 181 MW respectively (refer to Appendix B for details), the flow limit for line 7–8 was increased to accommodate the increased demand from the swapping of the Bus 7 and 19 loads. The transition rates for line 7–8 were varied to accentuate the impacts of transmission grid contingencies on the VPP’s performance. Readers should however note that the chosen values are by no means unique, and the sensitivity study could be easily conducted using alternative values for these parameters.

For every hour when the VPP has surplus energy ‘ $P_{0,ij}$ ’ to export to the transmission grid and there is an outage of line 7–8, $P_{inj,VPP,ij} = 0$, i.e., $P_{inj,VPP,ij} < P_{0,ij}$ for such hours. Comparing the formulations (5.8) – (5.13) with the corresponding indices presented in (4.21) – (4.29), it therefore becomes clear from Table 5.5 that the incorporation of transmission grid constraints and contingencies with the VPP assumed to be connected to Bus 7 leads to lesser exports (MVPPE), increased curtailments (ERENU) and reduced total energy injections (ESGD+ESGS) for the VPP as compared to the corresponding quantities obtained at HLI.

TABLE 5.5
COMPARISON OF PERFORMANCE INDICES OBTAINED AT HLI AND HLII (VPP MODELLED AT BUS 7)

<i>VPP performance indices</i>	<i>Hierarchical level</i>	
	<i>HLI</i>	<i>HLII</i>
MVPPE (MWh/year)	8.6767×10^2	8.6139×10^2
ERENU (MWh/year)	4.1095×10^2	4.134×10^2
ESGD (MWh/year)	4.9788×10^5	4.9788×10^5
ESGS (MWh/year)	4.7732×10^2	4.6993×10^2

Referring to the layout of the original RTS [25] presented in Appendix B, it can be observed that Bus 7 is characterized by 300 MW of installed generation capacity and 125 MW of peak load. So even though there is increased generation available to be dispatched from Bus 7 to the rest of the system during off-peak hours, the overall utilization of this capacity is low owing to the bottleneck created by the single line 7–8. Swapping the peak loads between Buses 7 and 19 and increasing the flow limit of line 7–8 for this second sensitivity study results in more local consumption of energy at Bus 7 as well as increased dispatches to the RTS, thereby increasing the utilization of the generation resources at Bus 7. The overall system reliability indices for this study, as presented in Table 5.6, are therefore found to be better off than their corresponding values presented in Tables 5.2 and 5.4. As with the previous tables, the incorporation

of the VPP at Bus 7 generally leads to reliability improvements for the overall system as well as at individual buses in Table 5.6, with the Bus 7 EFLC, EDLC and EENS values being reduced to 14.44%, 7.24% and 5.12% respectively of their original counterparts.

TABLE 5.6
COMPARISON OF ADEQUACY INDICES OBTAINED AT HLII (VPP MODELLED AT BUS 7)

<i>HLII adequacy indices</i>	<i>EFLC (occurrences/year)</i>		<i>EDLC (hours/year)</i>		<i>EENS (MWh/year)</i>	
	<i>Original RTS</i>	<i>RTS + VPP</i>	<i>Original RTS</i>	<i>RTS + VPP</i>	<i>Original RTS</i>	<i>RTS + VPP</i>
Bulk System	1.9974	1.3809	9.9849	6.2797	1.3554 $\times 10^3$	885.4527
Bus 1	0	0	0	0	0	0
Bus 2	0	0	0	0	0	0
Bus 3	0	0	0	0	0	0
Bus 4	4×10^{-3}	2.2857×10^{-3}	0.0117	5.7143×10^{-3}	0.4969	0.1941
Bus 5	5.7143×10^{-4}	0	2.8571×10^{-3}	0	0.1371	0
Bus 6	1.4286×10^{-3}	1.4286×10^{-3}	8.2857×10^{-3}	0.0151	0.7094	1.4529
Bus 7	0.0277	4×10^{-3}	0.2294	0.0166	6.0921	0.3116
Bus 8	1.0523	0.7243	5.0254	3.1346	481.7844	311.074
Bus 9	0	0	0	0	0	0
Bus 10	0.1294	0.082	0.5634	0.3306	65.1483	46.9731
Bus 13	0	0	0	0	0	0
Bus 14	1.1429×10^{-3}	5.7143×10^{-4}	3.4286×10^{-3}	1.4286×10^{-3}	0.3138	0.052
Bus 15	2.857×10^{-4}	0	1.7143×10^{-3}	0	0.2803	0
Bus 16	1.9651	1.3751	9.7351	6.2477	670.14	440.7694
Bus 18	0	0	0	0	0	0
Bus 19	0.32	0.2071	1.4829	0.8617	125.7151	82.2819
Bus 20	0.0226	0.0149	0.0843	0.0449	4.5692	2.3435

5.3.4. Impacts of Transmission Line Parameters on VPP's Performance

With the VPP still assumed to be modelled at RTS Bus 7, a final sensitivity study was performed for investigating the impacts of changes in transmission line parameters on the VPP's performance indices. Keeping remaining transmission grid and VPP parameters the same as those used for obtaining the results in Tables 5.5 and 5.6, the failure rate and the MTTR values associated with line 7–8 were increased using the following multipliers – 1, 3, 5, 7 and 9. The VPP performance metrics obtained as a function of the line 7–8 parametric multiplier are presented in Table 5.7.

As is clear from the table, the VPP's performance deteriorates, i.e., exports (MVPPE) are reduced, curtailments (ERENU) increase and its total energy injections (ESGD+ESGS) decrease, along with an increase in the line 7–8 parametric multiplier. Increased failure rates and MTTR values imply

higher occurrences of failures and longer repair times for line 7–8 over the course of the simulation, which in turn leads to increased isolation of the VPP at Bus 7. It should, however, be noted that the relative deterioration of the indices as a function of the line 7–8 parametric multiplier is quite insignificant (e.g., the MVPPE associated with multiplier 9 is 98.48% of its value obtained corresponding to multiplier 1) owing to the inherent intermittencies associated with the outputs of the renewable DGs constituting the VPP modelled in Chapter 4.

TABLE 5.7
COMPARISON OF VPP PERFORMANCE INDICES OBTAINED AS A FUNCTION OF LINE PARAMETERS

<i>VPP performance indices</i>	<i>Line 7–8 failure rate and MTTR multiplier</i>				
	1	3	5	7	9
MVPPE (MWh/year)	8.6657×10^2	8.6541×10^2	8.6139×10^2	8.5698×10^2	8.5344×10^2
ERENU (MWh/year)	4.1098×10^2	4.1164×10^2	4.134×10^2	4.1407×10^2	4.1665×10^2
ESGD (MWh/year)	4.9788×10^5	4.9788×10^5	4.9788×10^5	4.9789×10^5	4.9791×10^5
ESGS (MWh/year)	4.7601×10^2	4.7365×10^2	4.6993×10^2	4.5955×10^2	4.3694×10^2

5.4. Conclusions

This chapter presents a Monte Carlo sequential simulation based approach for assessing bulk power system adequacy incorporating the augmented VPP model developed in Chapter 4. A linearized DC load flow based OPF formulation is introduced for carrying out transmission network contingency analysis, and the MVPPE, ERENU, ESGS and ESGD formulations are suitably modified for highlighting the impacts of transmission grid constraints and contingencies on the VPP's performance. Sensitivity studies are carried out for investigating the effects of changes in the VPP's location as well as in transmission line parameters on the VPP performance and system adequacy indices.

It should be noted that the findings presented in Section 5.3 are a function of several factors, e.g., the OPF formulation (5.1) – (5.7), the load curtailment, generation dispatch and VPP operating policies adopted, the candidate buses selected for the VPP's connection as well as the test system data. The overall bulk power system adequacy assessment methodology proposed in this chapter is, however, generic, and can be used by VPP aggregators and system planners for conducting extensive simulations pertaining to the particular test system and operating policies under consideration. The findings from such simulations can provide critical inputs to the VPP aggregator regarding the impacts of transmission grid constraints and contingencies on the VPP's performance vis-à-vis its selected locations in the transmission network. Similarly, the results can also help system planners better understand the impacts of the VPP's incorporation on reliability at the system as well as at individual bus levels vis-à-vis the locations selected for the VPP's connection to the transmission grid.

CHAPTER 6

OPTIMAL VPP PLANNING FROM A COMPOSITE SYSTEM COST/WORTH PERSPECTIVE

This chapter presents a general methodology for performing economic feasibility studies while incorporating a VPP into an existing distribution network. The DC load flow based OPF formulation presented in Chapter 5 is combined with bulk power (composite) system cost/worth analysis techniques for determining an optimal DER portfolio for the VPP so as to minimize the total perceived costs pertaining to the VPP's participation in day-ahead electricity markets. The costs associated with the VPP are sub-divided into five categories – energy import, customer interruption, operation, investment and revenues. Different compositions and sizes of the DER mix are examined to determine the optimal portfolio which offers the highest cost savings to the VPP aggregator. Sensitivity studies are conducted by repeating the simulations with the VPP assumed to be connected at different transmission buses. These studies highlight the impacts of transmission grid constraints and contingencies as well as the load curtailment priority and customer interruption costs associated with individual buses (where the VPP is assumed to be connected) on the composition of the optimal DER portfolio along with the quantum of cost savings obtained. The presented optimal VPP planning strategy is implemented on the RTS in conjunction with the IEEE 69-bus distribution network using a sequential simulation algorithm, and the results obtained are presented and discussed.

6.1. Introduction

6.1.1. Literature Review

Several methodologies have been presented in [20–21, 61, 84, 91–95] pertaining to the economic assessment of power systems incorporating optimal dispatch of the aggregated outputs of DGs, ESDs and loads in energy and ancillary services markets. Reference [91] models several reinforcement measures being undertaken for incorporating new DGs in a given distribution network, and presents a multi-year distribution planning problem that aims to minimize the total network reinforcement, DG connection, DG curtailment and customer interruption costs over the entire planning horizon. The incremental and strategic investment approaches are used for solving the planning problem, and it is found that while the former produces lower system costs over the short-term, the latter minimizes the total costs over the entire duration of planning. An optimal dispatch schedule for a VPP's constituent DGs and curtailable loads is presented in [92], where the optimization problem aims to maximize the expected profits of the VPP aggregator from participation in day-ahead electricity markets. Revenues earned by renewable DGs

through renewable obligation certificate pricing as well as variable use-of-system charges pertaining to the VPP's access to the distribution network infrastructure are also modelled as part of the optimization formulation in [92]. A stochastic bi-level optimization formulation is presented in [93] for determining the optimal bidding strategy for a VPP comprising DGs, ESDs and curtailable loads in its portfolio. The upper level optimization problem performs maximization of the profits along with minimization of the real-time generation and consumption imbalance charges from the VPP's participation in day-ahead and balancing markets respectively. The lower level problem simulates the ISO's day-ahead market clearing tasks while minimizing the total system operating cost. Reference [93] demonstrates how a coordinated operation of the VPP's constituent DERs results in higher day-ahead profits and lower imbalance charges for the aggregator, and how its expected profits change as a function of its bidding strategy. The study presented in [93] is extended in [94] for incorporating transmission network constraints and contingencies as well as locational marginal pricing into the overall optimization formulation. A two-stage economic dispatch problem including VPPs is presented in [95]. While the first stage minimizes the overall system operating cost by optimally dispatching multiple VPPs connected at different transmission buses, the second stage minimizes the internal operating costs for individual VPPs by optimally distributing their concerned dispatch schedules (obtained from the first stage) amongst their constituent generating units.

6.1.2. Motivations

Several deficiencies in the literature reviewed in Section 6.1.1 were examined. The distribution network reliability cost/worth analyses presented in [20–21, 61] model the external grid as a single entity characterized by a Thevenin equivalent source impedance, hence the effects of transmission grid constraints and contingencies are ignored. Additionally, the VPP's energy exports to the transmission grid and in turn the corresponding revenues generated are not quantified in [20–21]. Transmission grid constraints and contingencies are also not modelled as part of the optimal distribution network planning and VPP dispatch strategies presented in [91] and [92] respectively. Though the hourly revenues earned from the VPP's energy injections into the external grid are quantified in [92], the marginal prices at the transmission buses are given as forecast values without explicitly considering any market clearing mechanism. In [93], the role of the VPP as a price-maker in trying to modify the day-ahead market clearing prices for extracting maximum profits for itself is investigated. However, transmission and distribution network topology and constraints are not incorporated into the bidding strategy formulation. References [84] and [94] model transmission constrained day-ahead market clearing mechanisms incorporating multiple VPPs bidding at different transmission buses, but the distribution networks are considered as lumped components in these publications and all associated topology and constraint related information are ignored. A similar lumped modelling of the distribution network is also carried out as part

of the transmission-constrained economic dispatch formulations presented in [95]. Moreover, customer interruption costs pertaining to potential load curtailments at the system buses are not modelled in [84] and [94]. A holistic VPP planning approach incorporating a specific market clearing mechanism while simultaneously considering topology and constraint related information of both transmission and distribution networks is therefore not presented in these publications. These deficiencies are partially addressed through the methodology presented in Chapter 5, however, an economic assessment of the VPP's performance is not performed in that chapter. This chapter bridges the gaps in the reviewed literature as well as in the work presented in Chapter 5 by proposing a general methodology for performing economic feasibility studies while incorporating a VPP into an existing distribution network. The studies are conducted while also taking into consideration the impacts of transmission grid constraints and contingencies on the different cost components pertaining to the VPP's participation in day-ahead electricity markets.

6.1.3. Contributions

The primary contributions of this chapter are as follows: 1) A holistic planning strategy for the VPP is presented by combining the DC load flow based OPF formulation presented in Chapter 5 with composite system cost/worth analysis techniques. The planning strategy aims to determine an optimal DER portfolio for the VPP, so as to minimize the total perceived costs pertaining to the VPP's participation in day-ahead electricity markets. 2) The costs associated with the VPP are sub-divided into five categories: energy import, customer interruption, operation, investment and revenues, and the relevant formulations are presented for each cost component. The formulations take into consideration a specific market clearing mechanism as well as the impacts of transmission grid constraints and contingencies. 3) A minimization model is proposed for examining different compositions and sizes of the VPP's DER mix to determine the optimal portfolio which offers the highest cost savings to the VPP aggregator. 4) Sensitivity studies are conducted by repeating the simulations with the VPP assumed to be connected at different transmission buses. The studies highlight the impacts of transmission grid constraints and contingencies as well as the load curtailment priority and customer interruption costs associated with individual buses (where the VPP is assumed to be connected) on the composition of the optimal DER portfolio along with the quantum of cost savings obtained.

6.2. Proposed VPP Planning Strategy

This section presents detailed formulations for the different cost components pertaining to the VPP's participation in day-ahead electricity markets. The market clearing mechanism employed for developing the formulations, the minimization model proposed for determining the VPP's optimal DER

portfolio as well as the overall system and VPP operating policies adopted in this chapter are also described in this section.

6.2.1. Cost Component Formulations

6.2.1.1. Import Cost

The expected annual cost incurred by the VPP aggregator in importing energy from the external grid is quantified using parameter ' π_{imp} ' (\$/year), and is formulated as follows:

$$\pi_{imp} = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} \lambda_{e,ij} * \text{abs} \left(\min(0, P_{inj,VPP,ij}) \right) \right) / N_y \quad (6.1)$$

where ' $P_{inj,VPP,ij}$ ' is obtained using (5.7) and ' $\lambda_{e,ij}$ ' (\$/MWh) is the uniform marginal price for hour 'i' of simulation year 'j' for the transmission constrained day-ahead electricity market model considered in this chapter.

Although different market models (e.g., bilateral contracts, PoolCo and hybrid models [96–97]) and pricing schemes (e.g., uniform, zonal and nodal pricing [96–98]) are currently employed across today's power markets, a pool-based day-ahead electricity market model with uniform marginal pricing [84, 97] is adopted in this chapter. As part of this model, power producers (including the VPP for hours when $P_{0,ij} \geq 0$) submit energy offers (price-quantity pairs) to the ISO for each hour 'i', which in turn clears the day-ahead market by executing the DC load flow based OPF formulation (5.1) – (5.7). The ISO is assumed to perform a single-sided auction [22] for serving inelastic demands at the different system buses, i.e., loads (including the VPP for hours when $P_{0,ij} < 0$) are modelled as price-takers in this chapter. The uniform marginal price ' $\lambda_{e,ij}$ ' therefore corresponds to the highest accepted energy offer of the most expensive generator dispatched by the ISO in hour 'i' using (5.1) – (5.7) [22, 84]. Note that the choice of the market clearing model as well as the pricing scheme adopted in this research work is however a generic one, and can be easily substituted by suitable alternatives as per the requirements of a given study.

6.2.1.2. Interruption Cost

The various methodologies available for quantifying the impacts of interruptions on customers can be broadly classified under the following three categories: indirect analytical evaluations, case studies of real-life blackouts and customer surveys [33]. Customer surveys are logistically difficult to conduct and require a lot of time-consuming post-processing efforts, however, this is the preferred approach taken by utilities for determining relevant interruption costs [28, 33]. The expected annual interruption costs (\$/year) are essentially a function of the concerned customer sector (e.g., residential, commercial, industrial, etc.) as well as the interruption characteristics (e.g., duration and frequency of interruptions) [28, 33, 99]. Customer sector normalized interruption costs (\$/kW) as a function of the interruption

duration are usually expressed using Sector Customer Damage Functions (SCDF) [33]. If the customer composition at a given bus is known along with the relative percentages of individual customer sectors in the total energy consumption and peak demand values associated with that bus, the sector normalized interruption costs can be proportionally weighted and combined to generate the Composite Customer Damage Function (CCDF) for the concerned bus [33]. The Bus CCDF therefore portrays the normalized interruption costs (\$/kW) calculated as a function of the interruption duration for the given customer mix at the bus. In the context of the composite system cost/worth analyses performed in this chapter, the CCDFs for Buses 7, 10 and 19 of the IEEE RTS (as presented in [28]) are depicted in Fig. 6.1 below.

Fig. 6.1 Composite customer damage functions for IEEE RTS Buses 7, 10 and 19

Denoting an interruption sequence ‘ I_s ’ as a series of consecutive hours when the VPP suffers from load curtailment (i.e., $C_{VPP,ij}$ computed using (5.1) – (5.7) is greater than 0), the expected annual interruption cost ‘ π_{int} ’ (\$/year) perceived to be incurred by the VPP aggregator is formulated as follows:

$$\pi_{int} = \left(\sum_{I_s=1}^{N_{int}} \lambda_{I_s} (dur_{I_s}) * C_{VPP,I_s}^{avg} \right) / N_y \quad (6.2)$$

where ‘ dur_{I_s} ’ (hours) is the duration of the interruption sequence ‘ I_s ’; ‘ $\lambda_{I_s}(dur_{I_s})$ ’ is the normalized interruption cost (\$/kW) for interruption duration ‘ dur_{I_s} ’ as extracted from the CCDF of the bus where the VPP is assumed to be connected; ‘ C_{VPP,I_s}^{avg} ’ (MW) is the average load curtailment experienced by the VPP

in the interruption sequence ‘ I_s ’; and ‘ N_{int} ’ is the total number of interruption sequences encountered over the course of the simulation. ‘ C_{VPP,I_s}^{avg} ’ is calculated as the ratio of the total VPP energy curtailed over the interruption sequence ‘ I_s ’ to the corresponding interruption duration ‘ dur_{I_s} ’ [85].

6.2.1.3. Revenues

The expected annual revenue earned by the VPP aggregator by exporting surplus energy to the external grid is quantified using parameter ‘ π_{rv} ’ (\$/year), and is formulated as follows:

$$\pi_{rv} = \left(\sum_{j=1}^{N_y} \sum_{l=1}^{8760} \lambda_{e,ij} * \max(0, P_{inj,VPP,ij}) \right) / N_y \quad (6.3)$$

where ‘ $P_{inj,VPP,ij}$ ’ is obtained using (5.7) and ‘ $\lambda_{e,ij}$ ’ is described in Section 6.2.1.1.

6.2.1.4. Investment and Operating Cost

While the investment costs (in \$/MW of installed capacity) for the VPP’s constituent WTGs, PV systems and ESDs are adapted from [100], those for the gas turbines are taken from [101]. Depending on the rated capacities of the DERs, the annual investment cost incurred by the VPP aggregator for installing the generation resources is quantified using parameter ‘ π_{inv} ’ (\$/year), and is calculated using the present value method described in [28]. The present value method essentially converts the total capital cost of the concerned DER into an equivalent annual component by considering the interest rate, inflation rate as well as the useful economic life of the generation resource [28].

The expected annual operating cost incurred by the VPP aggregator is quantified using parameter ‘ π_o ’ (\$/year). Operating costs can be further sub-divided into fixed (π_{of}) and variable (π_{ov}) components. The fixed cost component pertains to overheads like depreciation, interest and taxes which depend only on the magnitude of capacity installed and not on its actual use [24]. The fixed cost is assumed to be equal to 1% of the total investment cost associated with the particular VPP generation portfolio under consideration. The variable operating costs, on the other hand, depend on the actual degree of use of the generation resources, and is majorly composed of the corresponding fuel costs [24]. The variable operating costs for the WTGs, PV systems and ESDs are assumed to be zero for this research work [102–103]. This implies that the only contributing factor to the variable operating cost component (π_{ov}) is the fuel cost incurred from the operation of the gas turbines. Parameter ‘ π_{ov} ’ (\$/year) is therefore calculated as follows:

$$\pi_{ov} = \left(\sum_{j=1}^{N_y} \sum_{i=1}^{8760} \lambda_{CHP} * G_{VPP,ij}^c \right) / N_y \quad (6.4)$$

$$G_{VPP,ij}^c = \{ [\sum G_{k,max,ij}^c - \sum C_{k,ij}^{c,I}] - [\max(0, \min(\sum G_{k,max,ij}^c - \sum C_{k,ij}^{c,I}, P_{0,ij} - P_{inj,VPP,ij}))] \} \quad (6.5)$$

where ‘ λ_{CHP} ’ (\$/MWh) is the incremental generation cost associated with the VPP’s constituent gas turbines and is obtained from [101]; ‘ $G_{\text{VPP},ij}^c$ ’ (MW) represents the total energy injections of the gas turbines (conventional DGs); ‘ $\Sigma C_{k,ij}^{c,II}$ ’ (MW) denotes the total optimal curtailments carried out from the conventional DGs in Stages II.A or II.C in Chapter 4 and is obtained using (4.2) or (4.18) respectively; ‘ $\Sigma C_{k,ij}^{c,I}$ ’ (MW) denotes the total optimal curtailments carried out from the conventional DGs in Stage I in Chapter 4 and is obtained using (3.1); ‘ $P_{0,ij}$ ’ is obtained using (4.9) or (4.17); and ‘ $P_{\text{inj},\text{VPP},ij}$ ’ is obtained using (5.7). Note that since $\Sigma C_{k,ij}^{c,I} \geq \Sigma C_{k,ij}^{c,II}$ owing to some extra energy (from the DG curtailments) being dispatched for charging ESDs in Stages II.A or II.C, $G_{\text{VPP},ij}^c \geq 0$ for all ‘i’ and ‘j’.

6.2.2. Minimization Model for Determining Optimal DER Portfolio

For a given configuration of the VPP’s DER portfolio, the different cost components presented in (6.1) – (6.5) are computed first. The total expected annual cost pertaining to the VPP’s participation in day-ahead (DA) electricity markets is thereafter quantified using parameter ‘ π_{tot} ’ (\$/year), and is formulated as follows:

$$\pi_{\text{tot}} = \pi_{\text{imp}} + \pi_{\text{int}} + (\pi_{\text{ov}} + \pi_{\text{of}}) + \pi_{\text{inv}} - \pi_{\text{rv}} \quad (6.6)$$

A number of scenario and sub-scenario combinations ‘ ω ’ (more details in Section 6.3) are generated corresponding to different compositions, configurations and sizes of the VPP’s DER mix, and the ‘ π_{tot} ’ value calculated for a given combination is designated as ‘ $\pi_{\text{tot},\omega}$ ’. Parameter ‘ π_{tot} ’ is also computed for a base case scenario without the VPP being modelled. In this situation, the DNO is assumed to handle the operations of the concerned distribution network, and the total expected annual cost it incurs from its participation in the day-ahead market is designated as ‘ $\pi_{\text{tot},\text{base}}$ ’ (\$/year). The ‘ $\pi_{\text{tot},\omega}$ ’ values generated across all scenario/sub-scenario combinations are then compared, and the DER portfolio associated with the minimum ‘ $\pi_{\text{tot},\omega}$ ’ is determined to be the optimal, with the corresponding cost being designated as ‘ $\pi_{\text{tot},\text{opt}}$ ’. Finally, the cost savings this optimal DER portfolio offers to the VPP aggregator is calculated as follows:

$$\pi_{\text{sav}} = (\pi_{\text{tot},\text{base}} - \pi_{\text{tot},\text{opt}}) \quad (6.7)$$

where ‘ π_{sav} ’ (\$/year) denotes the aggregator’s (highest) cost savings from participation in DA electricity markets after incorporating the optimal DER portfolio into the distribution network under consideration. The optimal VPP planning strategy proposed in this chapter is graphically represented in Fig. 6.2.

Fig. 6.2 Flowchart for optimal VPP planning strategy

The DC load flow based OPF formulation used for simulating the ISO's day-ahead market clearing task is essentially the same as presented in (5.1) – (5.7), with only one exception. Unlike Chapter 5 where the VPP was assumed to be able to dispatch its excess energy on a priority basis for meeting external grid demand, all grid-connected generating units (including the VPP for hours when $P_{0,ij} \geq 0$) are assumed to be dispatched on a purely economic basis [88] in this chapter. The adopted operating policy for modelling the VPP's interactions with the ISO (in this chapter) is therefore similar to that presented in Section 5.2.3, with the only exception being that the VPP is assumed not to be receiving any incentives or subsidy (e.g., guaranteed feed-in tariffs) for dispatching its energy to the external grid. For each hour of the day-ahead market when the VPP is expected to be in a 'Producer' mode (i.e., $P_{0,ij} \geq 0$), the 'price-quantity pair' energy offer that it submits to the ISO can therefore be described as follows: a single block

of ' $P_{0,ij}$ ' MW of energy to be dispatched at a price equal to the incremental generation cost of the most expensive DG dispatched in the VPP's internal distribution network using the optimization formulation (4.2) – (4.9). On similar lines as mentioned in Section 5.2.3, it should be noted that the OPF formulation (5.1) – (5.7) along with the accompanying generation dispatch and VPP operating policies adopted in this chapter are generic in nature and can be easily substituted by appropriate alternatives as per the requirements of a given study.

6.3. Results and Discussions

This section presents the results obtained from the optimal VPP planning studies conducted as part of this chapter incorporating composite system cost/worth analysis techniques. The studies are performed on the IEEE RTS [25], with the IEEE 69-bus distribution network [27] being used for modelling the VPP as shown in the layout of Fig. 4.2. Different configurations of DGs and ESDs are examined, with candidate nodes for connecting the DERs as well as the number of DERs connected per node being the same as mentioned in Sections 3.2 and 4.2. The following eight scenarios are generated by changing the types of DGs connected at the various candidate nodes of the distribution network, with each scenario corresponding to a different configuration and composition of the VPP's DER mix.

- 1) *Scenario 1* – Only WTGs in the VPP's DER mix
- 2) *Scenario 2* – Only PV systems in the VPP's DER mix
- 3) *Scenario 3* – WTGs and PV systems in the VPP's DER mix, with the ratio of the total installed generation capacities of the respective DG types being equal to 25:75
- 4) *Scenario 4* – WTGs and PV systems in the VPP's DER mix, with the ratio of the total installed generation capacities of the respective DG types being equal to 50:50
- 5) *Scenario 5* – WTGs and PV systems in the VPP's DER mix, with the ratio of the total installed generation capacities of the respective DG types being equal to 75:25
- 6) *Scenario 6* – WTGs, PV systems and gas turbines in the VPP's DER mix, with the ratio of the total installed generation capacities of the respective DG types being equal to 15:15:70
- 7) *Scenario 7* – WTGs, PV systems and gas turbines in the VPP's DER mix, with the ratio of the total installed generation capacities of the respective DG types being equal to 25:25:50
- 8) *Scenario 8* – WTGs, PV systems and gas turbines in the VPP's DER mix, with the ratio of the total installed generation capacities of the respective DG types being equal to 35:35:30

Note that the total number of DGs considered in all eight scenarios is 26 (same as modelled in Section 3.2). Additionally, ESDs are not considered in the VPP's DER mix for any scenario, but are

modelled only for some specific test cases as mentioned in the following subsections. Each of the above scenarios are further divided into six sub-scenarios, with each corresponding to a given rated capacity assigned to individual DGs modelled in the concerned scenario. Rated capacities of individual DGs are varied in the following range for the six sub-scenarios: 1, 2, 3, 4, 5 and 6 MW respectively, with all DGs assumed to be having the same rated capacity for a particular simulation. Similar to Chapter 5, the VPP is assumed to be connected to Buses 7, 10 or 19 of the IEEE RTS, with three different groups of simulations being run corresponding to the VPP's locations. For a given location of the VPP in the transmission network, each simulation group therefore comprises 48 individual simulations (8 scenarios X 6 sub-scenarios), the results of which are presented in the following subsections. The VPP model corresponding to the IEEE 69-bus distribution network is characterized by an annual peak load of 181 MW. Other specifications regarding the failure/repair rate data and characteristic parameter values for the DGs, the system load profile as well as the ARMA models used for predicting hourly wind speed/solar irradiance values are presented in Section 3.4.1.

6.3.1. Optimal Planning Strategy for VPP Modelled at Bus 19

The different cost components pertaining to the VPP's participation in day-ahead electricity markets, as obtained for all the scenario and sub-scenario combinations described above, are presented in Table 6.1. The table also contains the relevant cost components calculated for the base case scenario without the VPP being modelled. The row headings for the different scenario/sub-scenario combinations in Table 6.1 consist of a mix of characters and a number separated by underscores. For a given combination, the characters and the number respectively denote the DG types and the rated capacity of individual DGs modelled in that simulation. For example, 'WTG_PV_Gas_5' in Scenario 7 implies that WTGs, PV systems and gas turbines were modelled in the VPP's DER mix for that simulation, with the ratio of the total installed generation capacities of the respective DG types being equal to 25:25:50 and the rated capacity of each DG being equal to 5 MW. For each scenario, the least total expected annual cost incurred by the VPP across all sub-scenarios is highlighted in italics in Table 6.1. Additionally, the optimal DER portfolio which offers the highest cost savings (with respect to the base case value ' $\pi_{\text{tot,base}}$ ') to the VPP aggregator across all scenario and sub-scenario combinations is italicized, and its corresponding total expected annual cost ' $\pi_{\text{tot,opt}}$ ' is highlighted in bold in the table. The following subsections contain additional discussions on the optimal DER portfolio with the VPP modelled at RTS Bus 19, as well as on variations in individual cost components as a function of the scenarios and sub-scenarios considered.

TABLE 6.1
COMPARISON OF COST COMPONENTS FOR VPP MODELLED AT RTS BUS 19

Cost components →		Import (k\$/year)	Interruption (k\$/year)	Operation (k\$/year)		Revenues (k\$/year)	Investment (k\$/year)	Total (k\$/year)
				Variable	Fixed			
Base case	Bus 19, no VPP	20,961.00	297.01	0.00	0.00	0.00	0.00	21,258.01
Scenario 1	WTG_1	20,012.00	207.08	0.00	72.80	0.00	802.02	21,093.90
	WTG_2	19,057.00	193.98	0.00	145.60	0.00	1,604.05	21,000.63
	WTG_3	18,135.00	182.50	0.00	218.40	0.10	2,406.07	20,941.86
	WTG_4	17,237.00	172.25	0.00	291.20	4.42	3,208.09	20,904.12
	WTG_5	16,386.00	163.11	0.00	364.00	22.79	4,010.12	20,900.44
	WTG_6	15,589.00	154.73	0.00	436.80	63.64	4,812.14	20,929.03
Scenario 2	PV_1	19,453.00	229.76	0.00	109.20	0.00	1,203.04	20,995.00
	PV_2	18,026.00	205.30	0.00	218.40	0.00	2,406.07	20,855.77
	PV_3	16,687.00	184.43	0.00	327.60	0.00	3,609.11	20,808.14
	PV_4	15,421.00	159.55	0.00	436.80	2.01	4,812.14	20,827.48
	PV_5	14,258.00	146.57	0.00	546.00	32.50	6,015.18	20,933.24
	PV_6	13,257.00	134.09	0.00	655.20	136.28	7,218.21	21,128.22
Scenario 3	WTG_PV_1	19,603.00	292.87	0.00	100.80	0.00	1,110.49	21,107.16
	WTG_PV_2	18,272.00	266.30	0.00	201.60	0.00	2,220.99	20,960.89
	WTG_PV_3	17,005.00	243.26	0.00	302.40	0.00	3,331.48	20,882.14
	WTG_PV_4	15,787.00	221.55	0.00	403.20	0.03	4,441.98	20,853.70
	WTG_PV_5	14,611.00	202.53	0.00	504.00	3.84	5,552.47	20,866.17
	WTG_PV_6	13,509.00	185.16	0.00	604.80	35.14	6,662.97	20,926.79
Scenario 4	WTG_PV_1	19,782.00	260.69	0.00	91.00	0.00	1,002.53	21,136.22
	WTG_PV_2	18,588.00	243.99	0.00	182.00	0.00	2,005.06	21,019.05
	WTG_PV_3	17,416.00	223.54	0.00	273.00	0.00	3,007.59	20,920.13
	WTG_PV_4	16,285.00	204.14	0.00	364.00	0.02	4,010.12	20,863.24
	WTG_PV_5	15,183.00	188.74	0.00	455.00	0.73	5,012.65	20,838.65
	WTG_PV_6	14,121.00	172.90	0.00	546.00	6.24	6,015.18	20,848.83
Scenario 5	WTG_PV_1	19,839.00	263.66	0.00	81.20	0.00	894.56	21,078.42
	WTG_PV_2	18,764.00	248.53	0.00	162.40	0.00	1,789.13	20,964.06
	WTG_PV_3	17,718.00	233.76	0.00	243.60	0.00	2,683.69	20,879.05
	WTG_PV_4	16,696.00	219.35	0.00	324.80	0.26	3,578.26	20,818.15
	WTG_PV_5	15,706.00	206.6740	0.00	406.00	4.73	4,472.82	20,786.77
	WTG_PV_6	14,759.00	194.59	0.00	487.20	21.06	5,367.39	20,787.12
Scenario 6	WTG_PV_Gas_1	17,489.00	229.46	8,597.50	208.00	0.00	2,422.74	28,946.71
	WTG_PV_Gas_2	14,196.00	178.45	17,195.00	416.00	0.00	4,845.49	36,830.94
	WTG_PV_Gas_3	11,045.00	135.80	25,793.00	624.00	0.01	7,268.23	44,866.02
	WTG_PV_Gas_4	8,040.40	100.17	34,390.00	832.00	45.13	9,690.98	53,008.42
	WTG_PV_Gas_5	5,323.10	70.47	42,988.00	1,040.00	980.23	12,113.72	60,555.05
	WTG_PV_Gas_6	3,137.60	46.35	51,585.00	1,248.00	4,051.70	14,536.46	66,501.72
Scenario 7	WTG_PV_Gas_1	18,015.00	200.26	6,688.10	182.00	0.00	2,107.14	27,192.50
	WTG_PV_Gas_2	15,174.00	162.19	13,376.00	364.00	0.00	4,214.28	33,290.47
	WTG_PV_Gas_3	12,428.00	129.09	20,064.00	546.00	0.00	6,321.42	39,488.51
	WTG_PV_Gas_4	9,802.10	101.63	26,753.00	728.00	2.30	8,428.56	45,810.99
	WTG_PV_Gas_5	7,293.70	78.69	33,441.00	910.00	151.01	10,535.70	52,108.08
	WTG_PV_Gas_6	5,051.50	58.96	40,129.00	1,092.00	1,192.70	12,642.84	57,781.61
Scenario 8	WTG_PV_Gas_1	18,760.00	188.09	3,820.60	143.00	0.00	1,633.74	24,545.42
	WTG_PV_Gas_2	16,607.00	158.69	7,639.20	286.00	0.00	3,267.47	27,958.36
	WTG_PV_Gas_3	14,519.00	142.17	11,457.00	429.00	0.00	4,901.21	31,448.37
	WTG_PV_Gas_4	12,498.00	122.86	15,276.00	572.00	0.15	6,534.94	35,003.65
	WTG_PV_Gas_5	10,543.00	106.08	19,096.00	715.00	13.31	8,168.68	38,615.44
	WTG_PV_Gas_6	8,678.00	90.35	22,915.00	858.00	144.82	9,802.42	42,198.94

6.3.1.1. Discussions on Import Costs

The expected annual import costs incurred by the VPP aggregator as a function of individual DG rated capacities are depicted in Fig. 6.3 for the different scenarios considered. The corresponding cost component for the base case scenario (without VPP) is also plotted in the figure for comparison sake. As expected, the incorporation of DERs into the VPP's internal distribution network reduces its energy requirements from the external grid, which in turn leads to lower import costs as compared to the base case scenario. The import costs are also found to be monotonically decreasing along with a corresponding increase in the installed capacity of individual DGs. Amongst the different scenarios, it is found that the import costs for Scenario 1 (WTGs only) are consistently higher than those for Scenario 2 (PV systems only). This is due to the fact that the intermittency associated with the wind resource at the selected site (refer to Sections 2.5 and 2.7 for more details) is higher than that of the solar. This is also corroborated in the discussions of Section 3.4.5. Over a long term, this therefore leads to increased demand for energy from the external grid for Scenario 1, and hence higher associated import costs. The import costs for Scenarios 3 – 5 (different proportions of WTGs and PV systems) are found to vary in between the boundaries of the Scenario 1 and 2 curves. The inclusion of gas turbines in the VPP's DG mix leads to reduced intermittencies in its generation portfolio, and hence substantially lower import costs for Scenarios 6 – 8. It can also be observed from Fig. 6.3 that higher the penetration level of conventional DGs in the VPP's DER mix, lower are the corresponding import costs obtained.

Fig. 6.3 Comparison of import costs for different scenarios and sub-scenarios

6.3.1.2. Discussions on Interruption Costs

The expected annual interruption costs incurred by the VPP aggregator as a function of individual DG rated capacities are depicted in Fig. 6.4 for the different scenarios considered. The corresponding cost component for the base case scenario (without VPP) is also plotted in the figure for comparison sake. As expected, the incorporation of DERs into the VPP's internal distribution network increases its self-sufficiency for meeting its own demands, which in turn leads to reduced chances of curtailments being carried out at the VPP bus and hence lower interruption costs as compared to the base case scenario. It is also seen that the interruption costs for Scenarios 3 – 5 (mix of WTGs and PV systems) are higher than those for Scenarios 1 and 2 (only one DG type in the VPP's generation portfolio). Though a combination of WTGs and PV systems in the VPP's DER mix smoothens out the volatility of the combined DG outputs, it also reduces the peak energy injections of the DGs as compared to scenarios with only one DG type. Over the long term, this in turn leads to higher chances of the VPP demand being curtailed for the former scenarios, and hence higher expected values of the interruption costs.

Fig. 6.4 Comparison of interruption costs for different scenarios and sub-scenarios

Comparing the failure rate and MTTR parameters of the modelled DGs for Scenarios 6 – 8, it is observed that the gas turbines are characterized by relatively higher values of these parameters as compared to those for the WTGs and the PV systems. At high penetration levels of conventional DGs in the VPP's DER mix (e.g., Scenario 6) and low rated capacities of individual DGs, the associated

interruption costs can therefore be found to be higher than those corresponding to scenarios with renewable only DG types (e.g., Scenario 1). As the DG rated capacities increase, however, the consistency of the conventional DG outputs more than compensates for their lack of availability, and the corresponding interruption costs rapidly decline with respect to their renewable only counterparts.

6.3.1.3. Discussions on Revenues

Along similar lines to the reasons provided in Section 6.3.1.2, the expected annual revenues earned by the VPP aggregator for Scenarios 3 – 5 (mix of WTGs and PV systems) are found to be consistently lower in Table 6.1 than those for Scenarios 1 and 2 (only one DG type in the VPP's generation portfolio). Reduced peak energy injections of the DGs for the former scenarios lead to decreased likelihood of the VPP being able to export excess energy to the external grid over the long term, which in turn causes the expected revenues to drop with respect to the corresponding values for scenarios with only one DG type. This is also corroborated in Section 3.4.5 in the discussions pertaining to MVPPE. On the other hand, the incorporation of gas turbines considerably boosts the VPP's energy export capabilities, and this generally leads to higher revenues being earned by the VPP aggregator for Scenarios 6 – 8 as compared to the renewable DG only scenarios 1 – 5. It can also be observed from Table 6.1 that higher the penetration level of conventional DGs in the VPP's DER mix and higher the rated capacities of individual DGs modelled, stronger are the aggregator's revenue earning potentials.

6.3.1.4. Discussions on Operating Costs

The procedures for computing fixed and variable operating cost components were presented in Section 6.2.1.4. The fixed annual operating costs incurred by the VPP aggregator are found to be monotonically increasing for all scenarios in Table 6.1 along with a corresponding increase in the DG installed capacities. Since the variable operating costs for the WTGs and PV systems are assumed to be zero, the variable operating costs associated with Scenarios 1 – 5 are equal to 0. The incorporation of gas turbines in the VPP's DG mix however leads to a sharp increase in the variable operating cost component for Scenarios 6 – 8, as indicated in Table 6.1.

6.3.1.5. Optimal DER Portfolio for VPP

Referring to Table 6.1, the optimal DER portfolio which offers the highest cost savings (with respect to the base case cost ' $\pi_{\text{tot,base}}$ ') to the VPP aggregator across all scenario and sub-scenario combinations corresponds to a 75:25 share of WTGs and PV systems in the VPP's DG mix, with the rated capacity of each DG being equal to 5 MW. This highlights the fact that even though the interruption costs and revenues associated with Scenarios 3 – 5 (mix of WTGs and PV systems) are respectively higher and

lower than those calculated for Scenarios 1 – 2 (only one DG type), a combination of renewable DG types in the VPP's generation portfolio can potentially offer higher cost benefits to the VPP aggregator over the long term. Additionally, even though the incorporation of gas turbines in the VPP's DG mix for Scenarios 6 – 8 generally leads to lower import and interruption costs as well as higher revenues earned for the VPP, the investment and the variable operating costs for these scenarios are so prohibitively high that they wipe off all benefits obtained through savings in the other cost components, and make these scenarios financially unsustainable from the perspective of the VPP aggregator.

In order to investigate the impacts of incorporating ESDs on the VPP's economic performance, 7 storage devices were assumed to be integrated with the IEEE 69-bus distribution network as described in Section 4.2. The DG configuration used for this study corresponded to that of the optimal DER portfolio from Table 6.1. The ESD rated capacities along with other relevant battery parameters were kept the same as specified in Section 4.4. A set of four simulations were run by varying the ESD rated capacities from Section 4.4 using the following multipliers: 0 (no ESDs), 0.5, 1, 1.5 and 2. All remaining parameters including the DG configuration as well as the system load profile were maintained the same for all four simulation runs. The different cost components pertaining to the VPP's participation in day-ahead electricity markets, as obtained after incorporating ESDs into the VPP's generation mix, are presented in Table 6.2.

TABLE 6.2
COMPARISON OF COST COMPONENTS INCORPORATING ESDs WITH VPP MODELLED AT BUS 19

	<i>Cost components →</i>	<i>Import (k\$/year)</i>	<i>Interruption (k\$/year)</i>	<i>Operation (k\$/year)</i>		<i>Revenues (k\$/year)</i>	<i>Investment (k\$/year)</i>	<i>Total (k\$/year)</i>
				<i>Variable</i>	<i>Fixed</i>			
<i>Scenario 5</i>	WTG_PV_5_ESD_0	15,706.00	206.6740	0.00	406.00	4.73	4,472.82	20,786.77
	WTG_PV_5_ESD_0.5	15704.00	206.6712	0.00	435.75	3.77	4956.99	21,299.64
	WTG_PV_5_ESD_1	15703.00	206.6698	0.00	465.50	3.01	5441.16	21,813.32
	WTG_PV_5_ESD_1.5	15702.30	206.6695	0.00	495.25	2.40	5925.33	22,327.15
	WTG_PV_5_ESD_2	15701.63	206.6695	0.00	525.00	1.93	6409.49	22,840.87

Similar to Table 6.1, the row headings for the different sub-scenarios in Table 6.2 consist of a mix of characters and numbers separated by underscores. While the characters denote the DER types (DGs or ESDs) modelled in a given simulation, the ESD rated capacity multiplier used for the concerned simulation is represented by the number appearing after the characters 'ESD'. The first row of the results presented in Table 6.2 corresponds to the case without ESDs, i.e., the costs are essentially those associated with the optimal DER portfolio determined in Table 6.1. Since a part of the VPP's excess energy ' $P_{VPP,ij}$ ' is used for charging the ESDs in Stage II.A in Chapter 4, the expected annual revenues earned by the VPP aggregator after incorporating ESDs are found to be slightly lower than the value obtained without the ESDs modelled. Similarly, the discharging of the ESDs during hours when $P_{VPP,ij} < 0$ implies that the expected annual import costs with the ESDs modelled are a bit lower than that obtained

without considering batteries. The extremely nominal benefits (lower expected annual import and interruption costs) obtained from the ESDs' incorporation in Table 6.2 can be attributed to several factors, e.g., the adopted VPP operating policy, ESD charging/discharging strategy, the simulation data used as well as the low utilization efficiency of the batteries. These factors are discussed in greater detail in Section 4.4.1. On the other hand, the rise in the annual investment and fixed operating costs associated with the ESDs' incorporation far outweigh the corresponding nominal benefits obtained. The net result is that the total expected annual costs incurred by the VPP aggregator with ESDs included are larger than that obtained without considering the ESDs. The optimal DER portfolio with the VPP modelled at Bus 19 therefore still corresponds to a 75:25 share of WTGs and PV systems in the VPP's DG mix with the rated capacity of each DG being 5 MW. The estimated cost savings this portfolio offers to the VPP aggregator is: $\pi_{\text{sav}} = (21258.01 - 20786.77) \text{ k\$/year} = 471.24 \text{ k\$/year}$ as calculated from Table 6.1.

6.3.2. Optimal Planning Strategy for VPP Modelled at Bus 10

A second group of simulations were run with the VPP assumed to be located at Bus 10 of the RTS (instead of Bus 19). The peak loads associated with Buses 10 and 19 were swapped for this case study, while keeping all remaining transmission grid and VPP parameters the same as specified in Section 6.3. The different cost components pertaining to the VPP's participation in day-ahead electricity markets, as obtained for this case study for all the scenarios and sub-scenarios described in Section 6.3, are presented in Table 6.3. The relative variations in the individual cost components in Table 6.3 as a function of the DG rated capacities are very similar to those observed in Table 6.1 and discussed in Sections 6.3.1.1 – 6.3.1.4. Some additional observations from the data presented in Table 6.3 are as follows.

Since the assumed IEAR value (and hence the load curtailment priority) associated with Bus 10 is higher than that for Bus 19, the overall curtailments are lesser (hence imports are higher) for this bus as compared to Bus 19. This is reflected by the higher expected annual import costs and lower expected annual interruption costs across all scenarios and sub-scenarios in Table 6.3 with respect to the corresponding values obtained in Table 6.1. Additionally, referring to the MVPPE values presented in Tables 5.1 and 5.3 corresponding to the VPP being modelled at RTS Buses 19 and 10 respectively, it may be recalled that the values were equal (refer to Section 5.3.1 for more details). This is further corroborated using the expected annual revenues listed in Table 6.3 and observing that the values are essentially the same as those presented in Table 6.1. Comparing equations (5.8) and (6.3), it may be noted that the expected annual revenue is basically the economic counterpart of the MVPPE index. Referring to Table 6.3, the optimal DER portfolio which offers the highest cost savings (with respect to the base case cost) to the VPP aggregator across all scenario and sub-scenario combinations once again corresponds to a 75:25 share of WTGs and PV systems in the VPP's DG mix, with the rated capacity of each DG being 5 MW.

TABLE 6.3
COMPARISON OF COST COMPONENTS FOR VPP MODELLED AT RTS BUS 10

Cost components →		Import (k\$/year)	Interruption (k\$/year)	Operation (k\$/year)		Revenues (k\$/year)	Investment (k\$/year)	Total (k\$/year)
				Variable	Fixed			
Base case	Bus 10, no VPP	20,973.00	98.33	0.00	0.00	0.00	0.00	21,071.33
Scenario 1	WTG_1	20,019.00	74.19	0.00	72.80	0.00	802.02	20,968.02
	WTG_2	19,063.00	69.90	0.00	145.60	0.00	1,604.05	20,882.55
	WTG_3	18,138.00	66.18	0.00	218.40	0.10	2,406.07	20,828.55
	WTG_4	17,242.00	62.68	0.00	291.20	4.36	3,208.09	20,799.62
	WTG_5	16,391.00	59.51	0.00	364.00	22.57	4,010.12	20,802.07
	WTG_6	15,593.00	56.39	0.00	436.80	63.22	4,812.14	20,835.11
Scenario 2	PV_1	19,462.00	41.67	0.00	109.20	0.00	1,203.04	20,815.91
	PV_2	18,033.00	37.29	0.00	218.40	0.00	2,406.07	20,694.76
	PV_3	16,693.00	34.18	0.00	327.60	0.00	3,609.11	20,663.89
	PV_4	15,426.00	31.79	0.00	436.80	2.01	4,812.14	20,704.73
	PV_5	14,263.00	29.80	0.00	546.00	32.49	6,015.18	20,821.49
	PV_6	13,261.00	27.97	0.00	655.20	136.22	7,218.21	21,026.16
Scenario 3	WTG_PV_1	19,614.00	80.26	0.00	100.80	0.00	1,110.49	20,905.56
	WTG_PV_2	18,282.00	72.99	0.00	201.60	0.00	2,220.99	20,777.58
	WTG_PV_3	17,014.00	67.48	0.00	302.40	0.00	3,331.48	20,715.36
	WTG_PV_4	15,794.00	62.36	0.00	403.20	0.03	4,441.98	20,701.51
	WTG_PV_5	14,617.00	57.15	0.00	504.00	3.77	5,552.47	20,726.85
	WTG_PV_6	13,515.00	52.46	0.00	604.80	35.08	6,662.97	20,800.15
Scenario 4	WTG_PV_1	19,792.00	46.39	0.00	91.00	0.00	1,002.53	20,931.92
	WTG_PV_2	18,596.00	41.73	0.00	182.00	0.00	2,005.06	20,824.79
	WTG_PV_3	17,424.00	37.46	0.00	273.00	0.00	3,007.59	20,742.05
	WTG_PV_4	16,291.00	33.62	0.00	364.00	0.02	4,010.12	20,698.72
	WTG_PV_5	15,188.00	29.88	0.00	455.00	0.73	5,012.65	20,684.80
	WTG_PV_6	14,126.00	26.25	0.00	546.00	6.24	6,015.18	20,707.18
Scenario 5	WTG_PV_1	19,849.00	93.41	0.00	81.20	0.00	894.56	20,918.17
	WTG_PV_2	18,773.00	86.67	0.00	162.40	0.00	1,789.13	20,811.20
	WTG_PV_3	17,725.00	80.87	0.00	243.60	0.00	2,683.69	20,733.16
	WTG_PV_4	16,703.00	75.70	0.00	324.80	0.24	3,578.26	20,681.51
	WTG_PV_5	15,712.00	70.4679	0.00	406.00	4.65	4,472.82	20,656.64
	WTG_PV_6	14,765.00	65.85	0.00	487.20	20.89	5,367.39	20,664.55
Scenario 6	WTG_PV_Gas_1	17,497.00	47.75	8,597.50	208.00	0.00	2,422.74	28,772.99
	WTG_PV_Gas_2	14,200.00	35.56	17,195.00	416.00	0.00	4,845.49	36,692.05
	WTG_PV_Gas_3	11,047.00	26.04	25,793.00	624.00	0.00	7,268.23	44,758.27
	WTG_PV_Gas_4	8,042.10	19.30	34,390.00	832.00	45.13	9,690.98	52,929.25
	WTG_PV_Gas_5	5,324.60	13.58	42,988.00	1,040.00	980.23	12,113.72	60,499.67
	WTG_PV_Gas_6	3,138.50	9.05	51,585.00	1,248.00	4,051.70	14,536.46	66,465.31
Scenario 7	WTG_PV_Gas_1	18,021.00	47.27	6,688.10	182.00	0.00	2,107.14	27,045.51
	WTG_PV_Gas_2	15,178.00	35.09	13,376.00	364.00	0.00	4,214.28	33,167.37
	WTG_PV_Gas_3	12,430.00	26.93	20,064.00	546.00	0.00	6,321.42	39,388.36
	WTG_PV_Gas_4	9,804.10	20.82	26,753.00	728.00	2.30	8,428.56	45,732.18
	WTG_PV_Gas_5	7,295.40	16.26	33,441.00	910.00	151.01	10,535.70	52,047.35
	WTG_PV_Gas_6	5,052.50	12.27	40,129.00	1,092.00	1,192.70	12,642.84	57,735.91
Scenario 8	WTG_PV_Gas_1	18,775.00	46.94	3,820.60	143.00	0.00	1,633.74	24,419.27
	WTG_PV_Gas_2	16,618.00	40.99	7,639.20	286.00	0.00	3,267.47	27,851.66
	WTG_PV_Gas_3	14,527.00	35.52	11,457.00	429.00	0.00	4,901.21	31,349.73
	WTG_PV_Gas_4	12,504.00	30.57	15,276.00	572.00	0.15	6,534.94	34,917.36
	WTG_PV_Gas_5	10,547.00	25.82	19,096.00	715.00	13.31	8,168.68	38,539.19
	WTG_PV_Gas_6	8,681.60	21.79	22,915.00	858.00	144.82	9,802.42	42,133.98

Similar to Section 6.3.1.5, the impacts of incorporating ESDs on the VPP's economic performance is investigated in this section by integrating 7 storage devices with the IEEE 69-bus distribution network as described in Section 4.2. The DG configuration used for this study corresponded to that of the optimal DER portfolio from Table 6.3. The ESD rated capacities along with other relevant battery parameters were kept the same as specified in Section 4.4. A set of four simulations were run by varying the ESD rated capacities from Section 4.4 using the following multipliers: 0 (no ESDs), 0.5, 1, 1.5 and 2. All remaining parameters including the DG configuration as well as the system load profile were kept the same for all four simulation runs. The different cost components pertaining to the VPP's participation in day-ahead electricity markets, as obtained after incorporating ESDs into the VPP's generation mix, are presented in Table 6.4.

TABLE 6.4
COMPARISON OF COST COMPONENTS INCORPORATING ESDS WITH VPP MODELLED AT BUS 10

<i>Cost components →</i>		<i>Import (k\$/year)</i>	<i>Interruption (k\$/year)</i>	<i>Operation (k\$/year)</i>		<i>Revenues (k\$/year)</i>	<i>Investment (k\$/year)</i>	<i>Total (k\$/year)</i>
				<i>Variable</i>	<i>Fixed</i>			
<i>Scenario 5</i>	WTG_PV_5_ESD_0	15,712.00	70.4679	0.00	406.00	4.65	4,472.82	20,656.64
	WTG_PV_5_ESD_0.5	15711.00	70.4670	0.00	435.75	3.71	4956.99	21,170.50
	WTG_PV_5_ESD_1	15710.00	70.4670	0.00	465.50	2.95	5441.16	21,684.18
	WTG_PV_5_ESD_1.5	15709.00	70.4670	0.00	495.25	2.35	5925.33	22,197.69
	WTG_PV_5_ESD_2	15708.00	70.4670	0.00	525.00	1.89	6409.49	22,711.08

Similar to the discussions presented for Table 6.2, it may be observed from Table 6.4 that the total expected annual costs incurred by the VPP aggregator with ESDs included in its DER mix are larger than that obtained without considering the ESDs. The optimal DER portfolio with the VPP modelled at Bus 10 therefore still corresponds to a 75:25 share of WTGs and PV systems in the VPP's DG mix with the rated capacity of each DG being 5 MW. The estimated cost savings this portfolio offers to the VPP aggregator is: $\pi_{\text{sav}} = (21071.33 - 20656.64) \text{ k\$/year} = 414.69 \text{ k\$/year}$ as calculated from Table 6.3. This result highlights the fact that even if the configuration of DERs is the same for the optimal portfolios determined corresponding to different locations of the VPP in a given transmission network, the quantum of cost savings obtained need not be equal for the two cases.

6.3.3. Optimal Planning Strategy for VPP Modelled at Bus 7

The final group of simulations were run with the VPP assumed to be located at Bus 7 of the RTS (instead of Bus 19). As mentioned in Section 5.3.3, the following modifications were incorporated into the RTS transmission network for obtaining these results. The peak loads associated with Buses 7 and 19 were swapped, the maximum flow limit associated with line 7–8 was increased from 175 MW to 230 MW, and the failure rate and MTTR values for this line were increased by 5 times. Remaining

transmission grid and VPP parameters were kept the same as specified in Section 6.3. The different cost components pertaining to the VPP's participation in day-ahead electricity markets, as obtained for this case study for all the scenarios and sub-scenarios described in Section 6.3, are presented in Table 6.5. The table also contains the relevant cost components calculated for the base case scenario without the VPP being modelled. The relative variations in the individual cost components in Table 6.5 as a function of the DG rated capacities are very similar to those observed in Table 6.1 and discussed in Sections 6.3.1.1 – 6.3.1.4. Some important observations which can be made from the data presented in Table 6.5 are as follows.

The assumed IEAR value (and hence the load curtailment priority) associated with Bus 7 is higher than that for both Buses 10 and 19. Additionally, it can be observed from the original RTS [25] that Bus 7 is characterized by 300 MW of installed generation capacity outside of the VPP. This implies that even if there is an outage in line 7–8 connecting Bus 7 to the rest of the RTS, the VPP's energy deficits (if any) could still be met using the local generating units. The overall effect of this is that curtailments are significantly lesser (hence imports are higher) for this bus as compared to those at Buses 10 and 19. This is reflected by the considerably higher expected annual import costs and lower expected annual interruption costs across all scenarios and sub-scenarios in Table 6.5 with respect to the corresponding values presented in Tables 6.1 and 6.3. Referring to the MVPPE values presented in Tables 5.1 and 5.5 corresponding to the VPP being modelled at RTS Buses 19 and 7 respectively, it may be recalled that the latter was found to be slightly lower than the former owing to the impacts of transmission grid constraints and contingencies arising out of the outage of line 7–8 (refer to Section 5.3.3 for more details). This is further corroborated using the expected annual revenues listed in Table 6.5 and observing that the values are slightly lower than the corresponding quantities presented in Tables 6.1 and 6.3. Referring to Table 6.5, it can be observed that the optimal DER portfolio which offers the highest cost savings (with respect to the base case cost) to the VPP aggregator across all scenario and sub-scenario combinations corresponds to a 50:50 share of WTGs and PV systems in the VPP's DG mix, with the rated capacity of each DG being 5 MW.

Similar to Section 6.3.1.5, the impacts of incorporating ESDs on the VPP's economic performance are investigated in this section by integrating 7 storage devices with the IEEE 69-bus distribution network as described in Section 4.2. The DG configuration used for this study corresponded to that of the optimal DER portfolio determined from Table 6.5. A set of four simulations were run by varying the ESD rated capacities from Section 4.4 using the following multipliers: 0 (no ESDs), 0.5, 1, 1.5 and 2. The different cost components pertaining to the VPP's participation in day-ahead electricity markets, as obtained for this study after incorporating ESDs into the VPP's generation mix, are presented in Table 6.6.

TABLE 6.5
COMPARISON OF COST COMPONENTS FOR VPP MODELLED AT RTS BUS 7

Cost components →		Import (k\$/year)	Interruption (k\$/year)	Operation (k\$/year)		Revenues (k\$/year)	Investment (k\$/year)	Total (k\$/year)
				Variable	Fixed			
Base case	Bus 7, no VPP	21,340.00	39.81	0.00	0.00	0.00	0.00	21,379.81
Scenario 1	WTG_1	20,230.00	36.59	0.00	72.80	0.00	802.02	21,141.42
	WTG_2	19,261.00	29.95	0.00	145.60	0.00	1,604.05	21,040.59
	WTG_3	18,323.00	25.57	0.00	218.40	0.08	2,406.07	20,972.96
	WTG_4	17,417.00	22.23	0.00	291.20	4.33	3,208.09	20,934.19
	WTG_5	16,555.00	19.73	0.00	364.00	22.53	4,010.12	20,926.32
	WTG_6	15,746.00	17.86	0.00	436.80	62.94	4,812.14	20,949.86
Scenario 2	PV_1	19,682.00	15.81	0.00	109.20	0.00	1,203.04	21,010.05
	PV_2	18,239.00	11.72	0.00	218.40	0.00	2,406.07	20,875.19
	PV_3	16,886.00	9.49	0.00	327.60	0.00	3,609.11	20,832.20
	PV_4	15,606.00	8.33	0.00	436.80	1.98	4,812.14	20,861.29
	PV_5	14,434.00	7.77	0.00	546.00	32.19	6,015.18	20,970.76
	PV_6	13,424.00	7.43	0.00	655.20	135.20	7,218.21	21,169.65
Scenario 3	WTG_PV_1	19,875.00	15.34	0.00	100.80	0.00	1,110.49	21,101.63
	WTG_PV_2	18,521.00	10.20	0.00	201.60	0.00	2,220.99	20,953.79
	WTG_PV_3	17,233.00	7.78	0.00	302.40	0.00	3,331.48	20,874.66
	WTG_PV_4	15,996.00	6.93	0.00	403.20	0.03	4,441.98	20,848.08
	WTG_PV_5	14,804.00	6.43	0.00	504.00	3.77	5,552.47	20,863.13
	WTG_PV_6	13,686.00	6.03	0.00	604.80	35.08	6,662.97	20,924.72
Scenario 4	WTG_PV_1	19,993.00	16.53	0.00	91.00	0.00	1,002.53	21,103.06
	WTG_PV_2	18,763.00	12.96	0.00	182.00	0.00	2,005.06	20,963.02
	WTG_PV_3	17,559.00	9.76	0.00	273.00	0.00	3,007.59	20,849.34
	WTG_PV_4	16,409.00	7.79	0.00	364.00	0.02	4,010.12	20,790.89
	WTG_PV_5	15,285.71	6.2401	0.00	455.00	0.70	5,012.65	20,758.89
	WTG_PV_6	14,213.00	5.38	0.00	546.00	6.04	6,015.18	20,773.52
Scenario 5	WTG_PV_1	20,163.00	31.88	0.00	81.20	0.00	894.56	21,170.65
	WTG_PV_2	19,077.00	25.13	0.00	162.40	0.00	1,789.13	21,053.66
	WTG_PV_3	18,018.00	20.09	0.00	243.60	0.00	2,683.69	20,965.38
	WTG_PV_4	16,983.00	16.17	0.00	324.80	0.24	3,578.26	20,901.99
	WTG_PV_5	15,981.00	13.85	0.00	406.00	4.65	4,472.82	20,869.02
	WTG_PV_6	15,021.00	12.35	0.00	487.20	20.64	5,367.39	20,867.30
	WTG_PV_7	14,113.00	11.36	0.00	568.40	55.22	6,261.95	20,899.48
Scenario 6	WTG_PV_Gas_1	17,730.00	8.89	8,597.50	208.00	0.00	2,422.74	28,967.13
	WTG_PV_Gas_2	14,388.00	1.53	17,195.00	416.00	0.00	4,845.49	36,846.02
	WTG_PV_Gas_3	11,195.00	0.14	25,780.00	624.00	0.00	7,268.23	44,867.37
	WTG_PV_Gas_4	8,143.90	0.00	34,373.00	832.00	43.63	9,690.98	52,996.24
	WTG_PV_Gas_5	5,384.70	0.00	42,958.00	1,040.00	963.60	12,113.72	60,532.82
	WTG_PV_Gas_6	3,170.30	0.00	51,523.00	1,248.00	3,998.30	14,536.46	66,479.46
Scenario 7	WTG_PV_Gas_1	18,221.00	10.93	6,688.10	182.00	0.00	2,107.14	27,209.17
	WTG_PV_Gas_2	15,341.00	3.17	13,376.00	364.00	0.00	4,214.28	33,298.45
	WTG_PV_Gas_3	12,562.00	0.33	20,064.00	546.00	0.00	6,321.42	39,493.75
	WTG_PV_Gas_4	9,903.00	0.03	26,742.00	728.00	2.15	8,428.56	45,799.44
	WTG_PV_Gas_5	7,364.00	0.00	33,426.00	910.00	147.79	10,535.70	52,087.91
	WTG_PV_Gas_6	5,096.30	0.00	40,103.00	1,092.00	1,178.20	12,642.84	57,755.94
Scenario 8	WTG_PV_Gas_1	19,055.00	19.17	3,820.60	143.00	0.00	1,633.74	24,671.50
	WTG_PV_Gas_2	16,853.00	11.61	7,639.20	286.00	0.00	3,267.47	28,057.28
	WTG_PV_Gas_3	14,743.00	5.72	11,457.00	429.00	0.00	4,901.21	31,535.93
	WTG_PV_Gas_4	12,691.00	2.02	15,275.00	572.00	0.12	6,534.94	35,074.84
	WTG_PV_Gas_5	10,703.00	0.56	19,093.00	715.00	12.90	8,168.68	38,667.34
	WTG_PV_Gas_6	8,807.90	0.00	22,908.00	858.00	144.24	9,802.42	42,232.07

TABLE 6.6
COMPARISON OF COST COMPONENTS INCORPORATING ESDs WITH VPP MODELLED AT BUS 7

Cost components →		Import (k\$/year)	Interruption (k\$/year)	Operation (k\$/year)		Revenues (k\$/year)	Investment (k\$/year)	Total (k\$/year)
				Variable	Fixed			
Scenario 4	WTG_PV_5_ESD_0	15,285.71	6.2401	0.00	455.00	0.70	5,012.65	20,758.89
	WTG_PV_5_ESD_0.5	15285.07	6.2401	0.00	484.75	0.49	5496.81	21,272.38
	WTG_PV_5_ESD_1	15284.62	6.2401	0.00	514.50	0.34	5980.98	21,786.00
	WTG_PV_5_ESD_1.5	15284.29	6.2401	0.00	544.25	0.23	6465.15	22,299.70
	WTG_PV_5_ESD_2	15284.04	6.2401	0.00	574.00	0.16	6949.32	22,813.44

It may be observed from Table 6.6 that the total expected annual costs incurred by the VPP aggregator with ESDs included in its DER mix are larger than that obtained without considering the ESDs. The optimal DER portfolio with the VPP modelled at Bus 7 therefore still corresponds to a 50:50 share of WTGs and PV systems in the VPP's DG mix, with the rated capacity of each DG being 5 MW. The estimated cost saving this portfolio offers to the VPP aggregator is: $\pi_{\text{sav}} = (21379.81 - 20758.89)$ k\$/year = 620.92 k\$/year as calculated from Table 6.5. This result demonstrates how the configuration of the optimal DER portfolio along with the quantum of cost savings obtained is a function of the VPP's location in the transmission network under consideration.

6.4. Conclusions

This chapter presents an optimal planning strategy for incorporating a VPP into an existing distribution network. Several cost components are defined for modelling the VPP's participation in transmission-constrained day-ahead electricity markets. Using composite system cost/worth analysis techniques, the proposed planning strategy aims to determine an optimal DER portfolio which minimizes the total costs (or conversely, offers the highest savings) incurred by the VPP aggregator. Extensive sensitivity studies are conducted to demonstrate how the configuration of the optimal DER portfolio as well as the cost savings obtained are functions of the transmission grid constraints and contingencies, the load curtailment priority as well as the customer interruption costs associated with the VPP's location in the transmission network.

On similar lines to the discussions in Section 5.4, it should be noted that the findings presented in Section 6.3 are a function of different factors, the most important of which include the load curtailment, generation dispatch and VPP operating policies adopted, the candidate buses selected for the VPP's connection to the transmission grid as well as the test system and cost parameter data used for the simulations. The overall planning approach presented in this chapter is, however, generic, and can help the VPP aggregator devise a suitable strategy for quantifying the potential economic benefits of incorporating DERs (using a VPP model) into the distribution network under consideration.

CHAPTER 7

CONCLUSIONS AND FUTURE RESEARCH DIRECTIONS

7.1. Conclusions

This thesis presents general methodologies for performing generation and bulk power system adequacy and cost/worth assessments incorporating an aggregated probabilistic model of renewable and conventional DGs, ESDs and loads under the umbrella of a VPP. Linearized network flow based optimization formulations are proposed for developing the aggregated VPP model at the transmission grid interface, while taking into consideration relevant distribution network information like topology and constraints. The developed VPP model is used in conjunction with a DC load flow based OPF formulation presented in this thesis for performing bulk power system adequacy studies. A holistic VPP planning strategy is proposed for determining the optimal DER portfolio so as to minimize the total perceived costs pertaining to the VPP's participation in day-ahead electricity markets. Apart from standard HLI and HLII adequacy indices, several new indices are introduced for quantifying different aspects of the VPP's performance at the respective hierarchical levels. Extensive sensitivity studies are conducted and important conclusions drawn from the simulation results obtained.

While Chapter 1 presents the motivations behind this research work as well as the important contributions made, Chapter 2 provides an overview of available reliability evaluation methodologies along with definitions of key HLI and HLII adequacy indices. ARMA models developed as part of this thesis for predicting hourly wind speed and solar irradiance values are also presented in Chapter 2.

Chapter 3 presents a general methodology for developing an equivalent VPP model at the transmission grid interface using a linearized network flow based optimization formulation. The developed VPP model is then used with other system parameters for performing generation adequacy assessment of the entire system. Several new performance indices – MVPPE, ERENU, ESGS and ESGD – are introduced for respectively quantifying the VPP's average annual energy exports to the external grid, the expected renewable DG curtailments as well as the expected system generation supplemented and displaced due to energy injections from the VPP's constituent DGs. The equivalent VPP model developed at the transmission grid interface is represented using a PDF, while explicitly differentiating the states where the VPP appears as a 'Producer' or a 'Consumer' with respect to an observer on the transmission grid side. It is shown how on an average the VPP appears to the external grid as a consumer. Sensitivity studies are conducted for investigating the impacts of changes in the total installed VPP generation capacity as well as the internal composition of the VPP's DG mix on the VPP performance and system reliability indices. It is shown how the VPP and system performances steadily improve along

with a corresponding increase in the VPP rated generation capacity. The results also demonstrate how replacing the gas turbines in the VPP's DG mix by intermittent renewables leads to sharp reductions in the annual average energy contributions from the DGs, and how the VPP's total energy outputs along with the overall system performance is the best for the scenario with a mix of renewable and conventional DGs in the VPP's portfolio.

Chapter 4 investigates the impacts of incorporating ESDs into the equivalent VPP model developed in Chapter 3, and subsequently uses it for performing generating system adequacy studies. A linearized multi-stage optimization formulation is proposed for developing the augmented VPP model, and several modes pertaining to the charging/discharging of the distributed ESDs are integrated with the different stages of the optimization formulation using a fair energy allocation based operating strategy. The VPP performance indices introduced in Chapter 3 are suitably modified for quantifying the impacts of the ESDs' incorporation on the VPP profile. Similar to Chapter 3, the augmented VPP model developed at the transmission grid interface incorporating ESDs is represented using a PDF. It is shown that even though the expected values of the PDFs characterising the VPP models with and without ESDs are nearly the same, their shapes are markedly different with a sharp spike around the $P_{0,ij} = 0$ line for the former distribution. The reductions in the MVPPE and ERENU indices as a result of the ESDs' incorporation are quantified in this chapter. Sensitivity studies are carried out for analysing the impacts of variations in the ESD rated capacities, the ESD charging/discharging periods as well as the load forecast uncertainty on the VPP performance and system adequacy indices. The results demonstrate how the MVPPE indices increase along with a corresponding increase in the ESD charging periods. The ERENU as well as the system LOLE and LOEE indices are found to be slightly deteriorating for higher ESD charging/discharging periods. The increase in the MVPPE, ERENU and ESGS indices and a gradual decline in the ESGD values along with a corresponding increase in the load forecast uncertainty is also demonstrated in the results presented in Chapter 4.

Chapter 5 introduces a systematic procedure for assessing bulk power system adequacy incorporating the augmented VPP model developed in Chapter 4. A linearized DC load flow based OPF formulation is proposed for performing transmission network contingency analysis, with the objective of minimization of the total load curtailment and generation costs for the system while enabling priority dispatch of the VPP output into the external grid. The MVPPE, ERENU, ESGS and ESGD formulations presented in Chapter 4 are suitably modified for highlighting the impacts of transmission grid constraints and contingencies on the VPP's performance. Sensitivity studies are carried out for investigating the impacts of variations in the VPP's point of connection to the transmission grid as well as in the failure and repair rates of transmission lines on the VPP's performance metrics. The relative benefits obtained in the bulk system as well as individual bus adequacy indices as a result of the VPP's incorporation are

quantified in this chapter. The results show how these benefits change as a function of the VPP's location in the transmission grid. Though it is generally expected that the VPP performance indices calculated at HLII would be worse off than their HLI counterparts owing to the incorporation of transmission grid constraints and contingencies in the former, the results also demonstrate how these indices may or may not deteriorate depending on the location of the VPP in the transmission grid.

Chapter 6 presents a holistic planning strategy for the VPP for determining an optimal DER portfolio which minimizes the total perceived costs pertaining to the VPP's participation in day-ahead electricity markets. A generic methodology is proposed for performing the planning studies by combining the DC load flow based OPF formulation presented in Chapter 5 with composite system cost/worth analysis techniques. The costs associated with the VPP are sub-divided into five categories: energy import, customer interruption, operation, investment and revenues. Relevant formulations are presented for each cost component, while taking into consideration a specific market clearing mechanism as well as transmission grid constraints and contingencies. A number of scenario and sub-scenario combinations are generated corresponding to different compositions and sizes of the VPP's DER mix, and a minimization model is proposed for determining the optimal portfolio which offers the highest cost savings for the VPP aggregator. Sensitivity studies are conducted by repeating the simulations with the VPP assumed to be connected at different transmission buses. Relative variations in the individual cost components as a function of the modelled scenarios and sub-scenarios are discussed. It is shown how the optimal DER portfolio corresponds to a scenario with a combination of renewable DG types in the VPP's generation portfolio. The results demonstrate how scenarios with conventional DGs and/or ESDs in the VPP's DER mix are unprofitable for the VPP aggregator. The chapter also presents the impacts of the VPP's location in the transmission grid on the configuration of the optimal DER portfolio along with the quantum of cost savings obtained.

The overall methodologies proposed in this thesis are tested using the RBTS as well as the IEEE RTS. Two distribution network test beds are separately used for modelling the VPP: the RBTS Bus 4 distribution network and the (larger) IEEE 69-bus distribution network. Sequential Monte Carlo techniques are employed for performing the simulations. The results presented can provide valuable information to the VPP aggregator and the ISO regarding important facets of the VPP's performance from its own as well as from the system's perspective. The results can also provide critical insights as to how the VPP's location in the transmission grid affects the following parameters: the VPP's performance, bulk power system reliability as well as the potential economic benefits which can be obtained from incorporating VPPs into existing power networks. Finally, the results can be very helpful for system planners while evaluating the additional investment and operating costs to be incurred for installing

individual DER components (e.g. DGs and ESDs) vis-à-vis the corresponding VPP performance and system adequacy benefits obtained.

7.2. Future Research Directions

Several general methodologies for performing generation and bulk power system adequacy and cost/worth assessments incorporating VPPs are presented in this thesis. Though there are many interesting findings from the results presented, following are some suggestions for potential future research areas.

- 1) The HLI and HLII adequacy assessment methodologies presented in this research work could be extended for performing well-being analysis of generating and bulk power systems incorporating VPPs. By further sub-dividing the system success states into ‘healthy’ and ‘marginal’ as part of the well-being analysis, the results can offer additional information to system planners pertaining to the VPP’s contributions from a security viewpoint.
- 2) The VPP’s internal distribution network demands are modelled as inelastic (with respect to price) in this thesis. The impacts of incorporating price-responsive curtailable demands in the VPP’s portfolio on the corresponding performance and system adequacy indices could be investigated.
- 3) The VPP modelled as part of the bulk power system adequacy studies carried out in Chapter 5 was assumed to be located at only one transmission bus for any given simulation. Given that the basic philosophy of a VPP is an entity which offers different services by managing multiple energy resources dispersed across the transmission grid (refer to Section 1.1 for more details), a good topic for future research could be to perform composite system studies considering multiple DERs located at different transmission buses. These DERs could either be assumed to be managed by a single VPP or by multiple players competing against each other. The proposed study can also incorporate wind speed/solar irradiance correlations amongst the multiple DER sites as well as bus load correlations amongst the different transmission buses.
- 4) The linearized optimization formulations presented throughout this thesis implicitly assume that network security is not compromised and all voltages are within acceptable bounds. Furthermore, a simplified DC load flow based approach is adopted in Section 5.2.2 since the VPP performance and system adequacy indices computed throughout this thesis are functions of active power only. A future study could introduce extended optimization formulations using AC power flow equations for investigating the impacts of the VPP’s energy injections

- on the voltage profile, reactive power flows and losses pertaining to the system under consideration.
- 5) Apart from the impacts of load forecast uncertainty investigated in Chapter 4, additional uncertainties in the component transition rates as well as in the ARMA model parameters used for predicting hourly wind speed/solar irradiance values are ignored in this thesis. Impacts of incorporating these uncertainties on the VPP performance and system adequacy indices could also be investigated.
 - 6) ARMA models were used in Chapter 2 as just one of several techniques available for predicting the hourly wind speed and solar irradiance values. Studying the impacts of using different forecasting tools (e.g., ARIMA, artificial neural networks, etc.) on the VPP performance and system reliability indices could be a good topic for future research.
 - 7) The impacts of incorporating alternative storage technologies, ESD charging/discharging strategies as well as operating policies on the obtained indices could also be investigated. An important thing to note is that the charging/discharging efficiencies and periods are assumed to be constant over the course of the simulations conducted as part of this thesis. A more practical approach would be to incorporate an appropriate ESD degradation model into the adequacy assessment procedure, wherein the efficiencies and the discharging period would be decreasing over time, whereas the charging period would be increasing over time. The impacts this model would have on the VPP performance and system adequacy indices could be analysed as well.
 - 8) Apart from the general market clearing model and pricing scheme used for performing the studies in Chapter 6, the impacts of using alternative clearing models (e.g., bilateral contracts and hybrid model) as well as schemes (e.g. zonal and nodal pricing) on the VPP performance and system adequacy indices could be studied. Additionally, it must be noted that uncertainties in the hourly wind speed, solar irradiance and load forecasts could introduce corresponding errors in the VPP's operating mode ('Producer' or 'Consumer') as well as the day-ahead market clearing price. The effects of incorporating these uncertainties and errors on the configuration of the optimal DER portfolio along with the quantum of resulting cost savings could be an interesting topic for future research.

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APPENDICES

APPENDIX A Roy Billinton Test System (RBTS)

The RBTS [24] is a 6-bus system with 9 transmission lines, 11 generating units, and a total installed capacity of 240 MW and a system peak load of 185 MW. The single line diagram of the RBTS is presented in Fig. A1. Details of the generating units and bus peak loads are presented in Table A1.

Fig. A1 Single line diagram of RBTS

TABLE A1
RBTS GENERATING UNITS AND BUS PEAK LOADS

Bus	Generating units				Peak load (MW)
	Rated capacity (MW)	No. of units	Failure rate (occurrences/year)	Repair rate (occurrences/year)	
1	40	2	6	194	0
	20	1	5	195	
	10	1	4	196	
2	40	1	3	147	20
	20	4	2.4	157.6	
	5	2	2	198	
3	-	0	-	-	85
4	-	0	-	-	40
5	-	0	-	-	20
6	-	0	-	-	20

APPENDIX B IEEE Reliability Test System (RTS)

The IEEE RTS [25] is a 24-bus system with 38 transmission lines, 32 generating units, and a total installed capacity of 3405 MW and a system peak load of 2850 MW. The single line diagram of the RTS [104] is presented in Fig. B1. Details of the generating units and bus peak loads are presented in Table B1. Transmission line parameters are listed in Table B2.

Fig. B1 Single line diagram of IEEE RTS

TABLE B1
IEEE RTS GENERATING UNITS AND BUS PEAK LOADS

<i>Bus</i>	<i>Generating units</i>				<i>Peak load (MW)</i>
	<i>Rated capacity (MW)</i>	<i>No. of units</i>	<i>Failure rate (occurrences/hour)</i>	<i>Repair rate (occurrences/hour)</i>	
1	20	2	1/450	1/50	108
	76	2	1/1960	1/40	
2	20	2	1/450	1/50	97
	76	2	1/1960	1/40	
3	-	0	-	-	180
4	-	0	-	-	74
5	-	0	-	-	71
6	-	0	-	-	136
7	100	3	1/1200	1/50	125
8	-	0	-	-	171
9	-	0	-	-	175
10	-	0	-	-	195
11	-	0	-	-	0
12	-	0	-	-	0
13	197	3	1/950	1/50	265
14	-	0	-	-	194
15	12	5	1/2940	1/60	317
	155	1	1/960	1/40	
16	155	1	1/960	1/40	100
17	-	0	-	-	0
18	400	1	1/1100	1/150	333
19	-	0	-	-	181
20	-	0	-	-	128
21	400	1	1/1100	1/150	0
22	50	6	1/1980	1/20	0
23	155	2	1/960	1/40	0
	350	1	1/1150	1/100	
24	-	0	-	-	0

TABLE B2
IEEE RTS TRANSMISSION LINE PARAMETERS

<i>From bus</i>	<i>To bus</i>	<i>X (pu)</i>	<i>Failure rate (occurrences/hour)</i>	<i>Repair rate (occurrences/hour)</i>	<i>P_{t,max} (MW)</i>
1	2	0.0139	0.24/8760	1/16.0	175
1	3	0.2112	0.51/8760	1/10.0	175
1	5	0.0845	0.33/8760	1/10.0	175
2	4	0.1267	0.39/8760	1/10.0	175
2	6	0.1920	0.48/8760	1/10.0	175
3	9	0.1190	0.38/8760	1/10.0	175
3	24	0.0839	0.02/8760	1/768.0	400
4	9	0.1037	0.36/8760	1/10.0	175
5	10	0.0883	0.34/8760	1/10.0	175
6	10	0.0605	0.33/8760	1/35.0	175
7	8	0.0614	0.30/8760	1/10.0	175
8	9	0.1651	0.44/8760	1/10.0	175
8	10	0.1651	0.44/8760	1/10.0	175
9	11	0.0839	0.02/8760	1/768.0	400
9	12	0.0839	0.02/8760	1/768.0	400
10	11	0.0839	0.02/8760	1/768.0	400
10	12	0.0839	0.02/8760	1/768.0	400
11	13	0.0476	0.40/8760	1/11.0	500
11	14	0.0418	0.39/8760	1/11.0	500
12	13	0.0476	0.40/8760	1/11.0	500
12	23	0.0966	0.52/8760	1/11.0	500
13	23	0.0865	0.49/8760	1/11.0	500
14	16	0.0389	0.38/8760	1/11.0	500
15	16	0.0173	0.33/8760	1/11.0	500
15	21	0.0490	0.41/8760	1/11.0	500
15	21	0.0490	0.41/8760	1/11.0	500
15	24	0.0519	0.41/8760	1/11.0	500
16	17	0.0259	0.35/8760	1/11.0	500
16	19	0.0231	0.34/8760	1/11.0	500
17	18	0.0144	0.32/8760	1/11.0	500
17	22	0.1053	0.54/8760	1/11.0	500
18	21	0.0259	0.35/8760	1/11.0	500
18	21	0.0259	0.35/8760	1/11.0	500
19	20	0.0396	0.38/8760	1/11.0	500
19	20	0.0396	0.38/8760	1/11.0	500
20	23	0.0216	0.34/8760	1/11.0	500
20	23	0.0216	0.34/8760	1/11.0	500
21	22	0.0678	0.45/8760	1/11.0	500

APPENDIX C RTS Hourly Load Data

The IEEE RTS randomly varying hourly load model [25] is used for performing the simulations reported in this thesis. The model is presented using tables C1 – C3, which respectively list the weekly peak loads in percent of the annual peak, the daily peak loads in percent of the weekly peak, and the hourly peak loads in percent of the daily peak. With a given annual peak load for the system under consideration, the model therefore produces 8736 hourly load values.

TABLE C1
RTS WEEKLY PEAK LOADS EXPRESSED IN PERCENT OF ANNUAL PEAK

<i>Week</i>	<i>Peak load (%)</i>	<i>Week</i>	<i>Peak load (%)</i>
1	86.2	27	75.5
2	90.0	28	81.6
3	87.8	29	80.1
4	83.4	30	88.0
5	88.0	31	72.2
6	84.1	32	77.6
7	83.2	33	80.0
8	80.6	34	72.9
9	74.0	35	72.6
10	73.7	36	70.5
11	71.5	37	78.0
12	72.7	38	69.5
13	70.4	39	72.4
14	75.0	40	72.4
15	72.1	41	74.3
16	80.0	42	74.4
17	75.4	43	80.0
18	83.7	44	88.1
19	87.0	45	88.5
20	88.0	46	90.9
21	85.6	47	94.0
22	81.1	48	89.0
23	90.0	49	94.2
24	88.7	50	97.0
25	89.6	51	100.0
26	86.1	52	95.2

TABLE C2
RTS DAILY PEAK LOADS EXPRESSED IN PERCENT OF WEEKLY PEAK

<i>Day</i>	<i>Peak load (%)</i>
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

TABLE C3
RTS HOURLY PEAK LOADS EXPRESSED IN PERCENT OF DAILY PEAK

<i>Hour</i>	<i>Winter weeks</i>		<i>Summer weeks</i>		<i>Spring/fall weeks</i>	
	<i>1 – 8 & 44 – 52</i>		<i>18 – 30</i>		<i>9 – 17 & 31 – 43</i>	
	<i>Weekday</i>	<i>Weekend</i>	<i>Weekday</i>	<i>Weekend</i>	<i>Weekday</i>	<i>Weekend</i>
12-1 am	67	78	64	74	63	75
1-2 am	63	72	60	70	62	73
2-3 am	60	68	58	66	60	69
3-4 am	59	66	56	65	58	66
4-5 am	59	64	56	64	59	65
5-6 am	60	65	58	62	65	65
6-7 am	74	66	64	62	72	68
7-8 am	86	70	76	66	85	74
8-9 am	95	80	87	81	95	83
9-10 am	96	88	95	86	99	89
10-11 am	96	90	99	91	100	92
11 am-12 pm	95	91	100	93	99	94
12-1pm	95	90	99	93	93	91
1-2 pm	95	88	100	92	92	90
2-3 pm	93	87	100	91	90	90
3-4 pm	94	87	97	91	88	86
4-5 pm	99	91	96	92	90	85
5-6 pm	100	100	96	94	92	88
6-7 pm	100	99	93	95	96	92
7-8 pm	96	97	92	95	98	100
8-9 pm	91	94	92	100	96	97
9-10 pm	83	92	93	93	90	95
10-11 pm	73	87	87	88	80	90
11 pm-12 am	63	81	72	80	70	85

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Journal papers:

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Conference papers:

- A. Bagchi, L. Goel and P. Wang, "Studying the impacts of incorporating energy storage devices into an aggregated probabilistic model of a virtual power plant," in *Proc. International Conference on Probabilistic Methods Applied to Power Systems (PMAPS)*, Oct. 2016, pp. 1–6.
- A. Bagchi, L. Goel and P. Wang, "Composite system adequacy assessment incorporating virtual power plants," in *Proc. International Conf. on Power System Technology (POWERCON)*, Wollongong, Australia, Sep. 2016, pp. 1–6.
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