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THE ANALYSIS OF DISTRIBUTED RESOURCES ON A LOAD SHARING RETICULATION NETWORK

by

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SUMMARY

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Abstract—Traditional reticulation network designs are outdated, based on single-value static yearly maximum demands, and do not consider the dynamic nature of load-side DR installations. The increasing presence of privately driven downstream renewable and storage system integration (supported by increasing energy costs, maturing of storage, PV, and inverter technology systems, and an unreliable external network supply) requires time-based analysis to advance beneficial, and mitigate detrimental, shared network parameter changes. Fundamental integration network impacts must be re-evaluated for grid integration acceptability and a modernised design approach, dependent on the capacity, capability, implementation, load-to-generation balancing, and power management of symbiotic integrated load-side DR (DG and/or ES) systems. These initial performance

factors were analysed by conducting time-based impact studies. Key concepts and approaches to the integration of PV DG, BESSs, and the combined DR system were identified and modelled at increasing levels of power penetration and energy arbitrage within the main distinctive reticulation network load profile forms in a visualised time-based impact analysis. By identifying individual DR operational parameters and limits, an optimal approach to DR utilisation and power control is defined. Variables include load profiles, load diversity, demands, load factors, PV DG and BESS parameters, system power control, voltage profiles, utilisation factors, reactive power requirements, and fault levels. The maximum levels of DR penetration were defined (creating an upper penetration limit) following the evaluation of DR network parameter impacts and forms the foundation of the power flow control algorithm governing PV DG and BESS operation for equipment synergy and the optimisation of integration advantages. The proposed power control enforces permanent load-side maximum demand reductions by up to 32%, with additional energy arbitrage operation enabled during peak period demands. This is achieved by limiting bi-directional power flow internally and maximising the combined DR system capability, utilisation, and operational synergy. Intermittent PV DG is selected for generation support, while more controllable BESS operation is chosen for targeted demand reduction applications in a give-and-take interface across all seasonal changes. The time-based analysis, integration methodology, DR penetration limits, and the developed power flow control algorithm provide an expectation baseline for future DR network integration studies, guidance for service agreement inclusions, and the modernisation of traditional network designs without the necessity of an external network smart grid system. This will encourage the integration of higher rated privately driven renewable and energy storage systems to enhance grid advancement for both external and load-side DR integrated networks.

LIST OF ABBREVIATIONS

ADMD	After Diversity Maximum Demand
Al	Aluminium
AMEU	Association of Municipal Electrical Undertakings
BESS	Battery Energy Storage System
BMK	Bulk Metering Kiosk
CapEx	Capital Expenditure
CES	Centralised Energy Storage
CF	Cost Factor
CFL	Compact Fluorescent Lamp
COVID	Corona Virus Disease
CSP	Concentrated Solar Power
DG	Distributed Generation
DIgSILENT	Digital Simulation and Electrical Network calculation program
DoD	Depth of Discharge
DR	Distributed Resource
DS	Distributed Storage
EPC	Engineering, Procurement, and Construction
ES	Energy Storage
FACTS	Flexible AC Transmission System
FAR	Floor Area Ratio
FIT	Feed-In Tariff
FSR	Floor Space Ratio

GCC	Grid Code Compliance
GLA	Gross Leasable (Floor) Area
GOOSE	Generic Object Orientated Substation Event
HV	High Voltage
HVAC	Heating, Ventilation and Air-Conditioning
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IoT	Internet of Things
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRR	Internal Rate of Return
LED	Light Emitting Diode
LF	Load Factor
LV	Low Voltage
LCOE	Levelized Cost of Energy
LCUS	Levelized Cost of Using (Energy) Storage
MD	Maximum Demand
MFS	Minimum Functional Specification
MIRR	Modified Internal Rate of Return
MSS	Miniature Substation (Distribution Transformer)
MV	Medium Voltage
NAC	Network Access Charge
NDC	Network Demand Charge
NDP	Network Development Plans
NERSA	National Energy Regulator of South Africa

NMD	Notified Maximum Demand
NMP	Network Master Plans
NPV	Net Present Value
NSP	Network Service Provider
OEM	Original Equipment Manufacturer
OLTC	On Load Tap Changer
OpEx	Operational Expenditure
PCS	Power Conversion System
PDF	Probability Density Function
PEP	Prevalent Engineering Practice
PPA	Power Purchase Agreement
PPC	Power Park Controller
PRR	Power Ramp Rate
PV	Photovoltaic
RE	Renewable Energy
RMU	Ring Main Unit
SSEG	Small Scale Embedded Generation
SANS	South African National Standards
SCADA	Supervisory Control and Data Acquisition
SLD	Single Line Diagram
SoC	State of Charge
TOU	Time of Use
TRFR	Transformer
XLPE	Cross-linked polyethylene

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CHAPTER 1 INTRODUCTION

1.1 PROBLEM STATEMENT

1.1.1 Context of the problem

Traditional electrical networks consist of large generation plants and long-spanning HV transmission systems supplying stepped-down MV and LV loads with a unidirectional flow of power. With the introduction of smaller-scale power end-user based DR installations, defined as a combination of small-scale DG (or SSEG [1]) together with distributed ES systems spread over multiple locations [2], the traditional electrical network is modernised with the focus now shifting to the connection, integration, and impacts of downstream secondary systems to the grid through bi-directional power flows [3]. An integrated DR system can be co-located with local loads on the end-user (decentralised/internal) or utility (centralised/external) side of the meter and provides network support in conjunction with the main utility system.

The characteristic nature of load-side/downstream internal network integrated DRs provide the end-user with an alternative controllable source of supply, reduces external grid dependency, and mitigates supply authority control [4], but carries the risk that any disturbance in an internal network integrated DR system could interrupt the reliability (for example, upstream tripping) or affect the power quality of all shared external connections [3]. This introduces a new level of grid uncertainty to planning [5], control [6], optimisation [7], and power management [8] within electrical network design and operation, and must be considered to prevent adverse network implications [9] when conducting master [10] and electrification network planning [11].

Roof mounted PV systems are becoming increasingly sought-after, supported by the global emphasis on sustainable development [12], improving technology energy efficiencies [13], favourable local (South African) solar irradiance levels, and attractive feasibility studies. This is supported by NSP status statistics indicating a 350% yearly increase in installed rooftop PV capacities, rising from around 983 MW to 4.4 GW between 2022 to 2023 [14]. From decreasing PV system costs through a competitive technology market, local NSP unreliability, and the consistent increase of supply authority energy tariffs [15], [16], attractive investment opportunities have been proven feasible for small to large scale PV DG systems [4] with recent financial feasibility studies showing achievable payback periods of under 5 years for grid-tied commercial systems. System payback periods will improve as the technology develops, with the projected PV system LCOE predicted to decline to as low as R 0.46/kWh by 2030 [17]. This will drive the adoption of higher rated internal network (private or developer driven) integrated systems, supported by attractive project specific financial feasibility studies.

An increasing presence of grid integrated BESSs is also expected as these modular ES assets have proven bankability through experienced, trusted, and competitive ES integrators. Significant technological advancements within the ES field (greatly supported by electric vehicle research) have carried over to MWh applications offering a wide range of operational advantages as the technology matures. BESSs are theoretically able to replace gas generation systems in the industrial sector [17], provide backup supply, increase grid stability, improve load gradients, and form a crucial component in any low inertia network through grid forming, black start capability, or spinning reserve operations. BESS capabilities and practical necessity (specifically within higher renewable penetration levels) expand market potential and motivate further research and technological improvement. This momentum is leading to an increased network presence of integrated BESSs within industrial as well as commercial networks as these systems are becoming more financially viable and operationally feasible for internal network developers.

National incentives, such as the South African Section 12B on renewable assets (Tax Act No. 58 of 1962 as amended [18]), promote the integration of SSEG. In 2019, the South African SSEG application process was streamlined by NERSA to increase the power capacity level restriction of privately owned DG systems from 1 MW to 10 MW. Shortly after due to necessity, regulations published in August 2021 [19] further increased the distributed generation licencing threshold for projects up to 100 MW to boost economic confidence, attract investors, and reduce the impact of NSP load shedding through a simplified NERSA application procedure. Other administrative DG fees are also expected to drop significantly.

The unavoidable presence of DR systems (PV DG and/or ES) within network planning is supported by the 2019 IRP [20], 2023 NSP statistics [14], and South African energy forecasts [17]. This is attributable to private reticulation network commercial/industrial developers and installers (followed by residential developments with the introduction of ES [17]), providing a privatised driven backbone for a future smart grid system [21], following increasingly feasible BESSs and DG capabilities that are soon to compete with other non-renewable energy sources [13]. With the supporting backbone of BESSs, advanced integration power control has the potential to effectively utilise renewable generation, specifically within load profiles that do not match solar radiation profiles. DR integration optimisation through power management and control will enhance the viability of integrated DR systems, reduce renewable energy curtailment, and enforce operational synergy.

In contrast to traditional design methodologies based on static yearly load maximum demands, the dynamic nature of integrated BESSs and renewable DG requires additional time-based load and generation profile studies. Time-based integration profile studies should include the various new operational aspects and additional equipment variables that inverter-based DR systems will bring to modernised reticulation network designs, parameters, and operation [9], but remain limited within existing literature coverage. Detailed and systematic load profile optimisation analysis, governed by optimised power management and control, is therefore a crucial starting point to set the baseline for the next-phase of integration studies, considering that poor DR integration can result in out of bounds voltage levels, reverse power flow complications, power losses, reactive power complexities, frequency shifts, worsening load factors, stability problems, and other related issues affecting all connected loads in the shared upstream network [3].

A future smart grid communication backbone could provide the operational link between DR integrated internal networks and external grids with the capability to effectively manage higher levels of all connected DR contributions, specifically for protection and end-user energy export applications. However, it could be many years before smart grid infrastructure is designed, tested, and practically feasible in contrast to the rapid expansion observed in integrated DR systems [14], [22]. To ensure network advancement while mitigating integration drawbacks in the absence of smart grid management capability, profile modelling of internal network integrated PV DG, BESSs (and selected operation), and the combined DR system with optimised power flow control, is required. This analysis should be modelled using seasonal (high demand, low demand) and daily (weekday, weekend) time-based operational profiles. A design methodology, with a focus on optimal DR integration and control, is required to provide an initial DR profile design approach for internal and external grid-supporting synergy.

1.1.2 Research gap

The electrical parameters used in load forecasting and traditional reticulation network design include yearly maximum demands (calculated from ADMDs), load diversity, load and loss factors, and equipment utilisation factors. The integration of PV DG and BESSs will significantly change traditional load profiles by time-shifting the (possibly also reduced) maximum demands from the norm, altering load and loss factors, and changing equipment (lines, transformers, cables, switchgear) utilisation factors [23] and switchgear ratings (short-circuit levels).

Numerous installations of various sized DG projects are being implemented at distribution (MV) level [9], [24] - [31]. An information gap is observed in modernising and optimising traditional reticulation network design procedures to include time-based (seasonal and daily) internal and external network load profile changes resulting from LV PV DG and MV BESS integration within an internal DR network, which are not being considered in the traditional single value high-demand ADMD focussed static design methodologies and network operations. Understanding the fundamental changes that DR integration will have on load profiles, governed by optimised power control, will pave the way for a more realistic network design approach prior to detailed dynamic integration studies.

The inevitable integration of high magnitude DRs, and the resulting load profile changes in traditional distribution and reticulation networks, should be evaluated for a modernised design approach baseline in preparation for a future smart grid network.

1.2 RESEARCH OBJECTIVES AND QUESTIONS

A significant increase is ES systems is expected within electrical networks and should be included in electrical network planning [17]. BESSs are the preferred and most common technology type for storage systems and will become the most in-demand ES type in the following years [32]. Various methods of BESS operational control (discharge/recharge duty cycles) have been analysed in literature [33]. Therefore:

- How can various ES discharge/recharge cycles be modelled (including practical BESS limitations) to determine the optimal approach to energy arbitrage and a permanent reduction of the maximum load demand?
- How can the absolute maximum installed ES capacity limit, before adverse demand profile consequences, be estimated?
- How will the increasing presence of BESSs affect load profiles, load parameters, and traditional design procedures in a greater mixed-use reticulation network?
- How can the operational models of BESSs be controlled to optimise and improve load parameters, load factors, load profiles, and permanently reduce the overall system maximum demand?

PV power generation is predicted to be the most in-demand DG technology in the future [17], [21], [32], but power output remains dependent on uncontrollable external factors such as temperature and weather. Traditional reticulation design procedures do not include the impact of PV DG network penetration. Therefore:

- How can PV DG penetration profiles be modelled as a supplementary energy reduction source in network design?
- How will increasing levels of PV energy penetration impact load profiles, load parameters, and traditional design procedures in a greater mixed-use reticulation network?

To utilise the collective benefits provided by PV DG and BESS synergism, a power management control algorithm is required to prevent potential adverse effects and ensure power flow regulation in compliance with of the local grid codes [34], [35]. Therefore:

- Can the DR power flow control algorithm be optimised to permanently reduce load maximum demands, improve the load factor, prioritise BESS recharge from sources with the lowest energy cost (local PV DG surplus followed by off-peak utility), and prevent recharge in unsuitable or expensive utility TOU periods?
- Can power flow control be optimised to retain and utilise surplus generated energy locally (within the internal network before external feed-in) to minimise renewable source curtailment and reduce unnecessary bi-directional power flows and associated losses?
- What are the considerations and limitations for utilising surplus generated PV energy for peak tariff load reduction with the support of BESS and control?
- Ultimately, how can DR technologies be combined and controlled to provide benefits to the utility (load demands, utilisation factors, losses, load factors, network inertia, reactive power support) and the internal network (cost savings)?

Weekday commercial load profiles resemble a perfect fit for grid-tied PV DG installations. Non-operational/weekend commercial loads are significantly lower, resulting in potential wasted/curtailed PV generated energy. Residential load profiles do not match solar radiation profiles (with lower midday demands and load peaks outside PV generation times), making high penetration PV installations for maximum demand reductions impractical without the use of expensive ES support systems. Both scenarios indicate the availability of unused PV generated energy between diversified mixed-use loads that could be transferred back to the external network in support of other supply demanding loads. Therefore:

- What would the electrical impact be if surplus generated energy from distributed PV sources is transferred back into the external network?
- Can grid feed-in be supported (with no adverse effects on utility infrastructure) without advanced external network smart grid control and monitoring capability, or should power sharing be limited to local (internal network) boundaries?

Internal network load profiles will be altered significantly from the norm with the integration of DRs. This includes intermittent midday demand changes from PV DG, demand changes from BESS discharge and recharge (governed by operational control), and the possibility of irregular surplus generated PV energy that could result in bi-directional power flow within internal or external networks. Network parameters that include maximum demand, coincident demand, demand factor, load factor, diversity factor, short-circuit levels, and infrastructure equipment loading (utilisation factor) need to be reinvestigated with acceptable grid-code compliance criteria (reactive power, voltage levels, etc.) to local standards for modernising DR network design methodologies. Therefore:

- Will the altered POC load profiles, voltage profiles, short-circuit levels, and power factor changes from integrated DR systems (controlled by power management control algorithms) still adhere to electrical compliance standards such as NRS 097-2-3 [36] and supply authority grid codes [34], [35]?
- What is the significance of power factor control functionality within DR POC busses for the benefit of the greater reticulation system and grid compliance criteria?

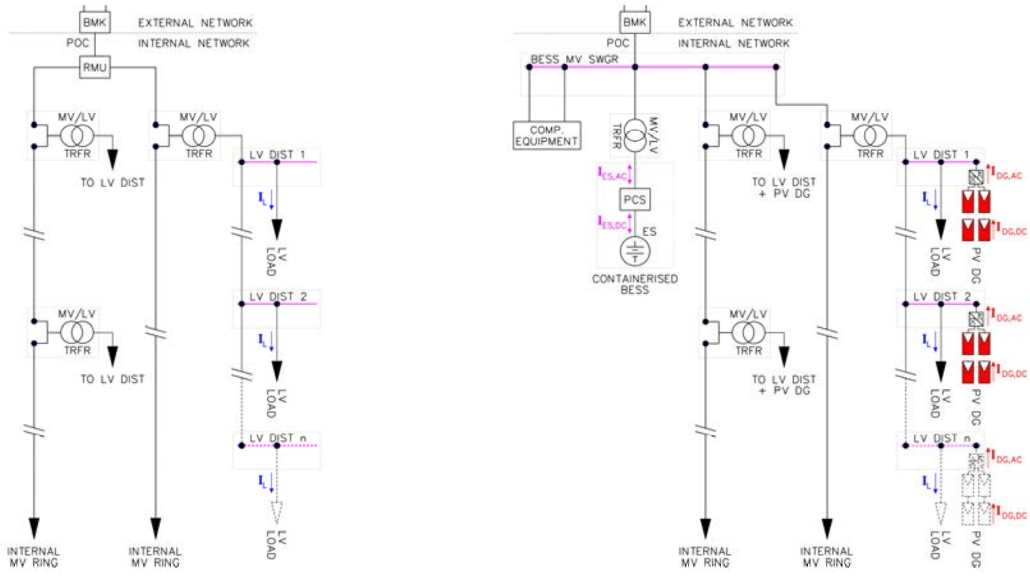
- How will the increasing presence of internal network PV DG and BESSs in a mixed-use network impact electrical parameters used in electrical network design, load forecasting, and external network infrastructure?

1.3 APPROACH

Load profile design considerations, methodologies, and power control will be developed for a mixed-use DR enabled network. Internal networks will be modernised to include high penetrations of distributed power units (PV DG) and ES applications (BESSs) [37] to resemble the following key Microgrid concepts consisting of [21]:

- Subsections distribution (MV) and reticulation (LV) load sharing networks.
- Both AC and DC components and subsections.
- Distributed transformers and loads.
- Integrated PV DG units and BESS components to form a complete DR system.
- Compensation equipment for grid code operational acceptability.
- A single external network common coupling point (POC) for utility connection and metering.
- One common Power Park Controller for all DR and compensation equipment control.
- Electrical variables monitoring and control capabilities for dynamic billing optimisations and grid code operational acceptability.
- Operation capabilities in grid-tied load sharing or standalone mode.
- All required protection functionalities.
- Compliance with all local renewable generation and energy storage connection standards.

The internal reticulation network representation of Figure 1.1a (traditional design) will be modernised to resemble the key Microgrid concepts in Figure 1.1b (DR enabled design). Refer to Chapter 4 Figure 4.2 (external network) and Figure 4.3 (internal network) for the simulation representative diagrams.



(a) (b)

Figure 1.1. Internal network representation of non-domestic and domestic zones.

(a) Traditional network design. (b) DR enabled network design.

The study will be conducted in two phases, namely initial profile modelling and optimisation (Chapter 3) followed by case study verification (Chapter 4). The internal reticulation network representation of Figure 1.1 is used for the analysis of domestic zones (morning and afternoon peaks, lower midday demands) and non-domestic zones (weekday midday peaks, low weekend demands). These zones represent the two main load profile forms, consisting of either warehousing facilities, multiple offices in a business park, or multiple housing blocks in a residential complex. Each internal DR load-sharing network of Figure 1.1b includes a modular BESS (including Power Conversion System (PCS) transformer/s) and compensation equipment, as well as multiple MV/LV distribution transformers each connected to a distributed LV bus with PV DG systems. Roof mounted PV DG systems are envisioned to be distributed across the developments with multiple inverters feeding into the main LV switchgear. BESSs (including modular switchgear and compensation equipment as required) will be installed close to the POC. A BMK provides the internal to external network POC, irrespective of authorised load capacity but within equipment power ratings. Integration is assumed to comply with the IEEE interconnection guideline [38], have all feeder and interconnection protection interlocks [39], and employ all the required communication protocols [40] necessary for safe DR integration. DR load profiles will be created from first principle calculations (Addendum A) to determine and visualise the impacts of all separate system variables. All simulations will be verified using PowerFactory DIgSILENT software.

1.3.1 Profile modelling

In preparation for the case study, real load measurement data from similar and existing developments will be used as baseline profiles, providing improved practical accuracy over mathematical or statistical estimations. These load profiles will be altered by incorporating increasing levels of PV DG penetration and include various approaches to ES and power control to determine the optimal methodology for DR load profile improvement. The methodologies, power control algorithms, and altered load profiles from this section will be used to further investigate network parameters in the case study. The two main distinctive reticulation network load profile forms will be simulated to determine the effects of the following three scenarios:

Base case:

This scenario excludes all DR components, similar to Figure 1.1a. This forms the base case (baseline) scenario, simulating traditional design parameters for comparative purposes.

Integration of BESSs and power control:

This scenario will determine the impact on network parameters with optimised ES and power control, similar to Figure 1.1b, but without PV DG capability. This scenario simulates DR network parameters when intermittent PV renewable generation is unavailable following non-ideal weather or other external factors. Various approaches to ES discharge models and control will be investigated and simulated to determine the ideal approach to be used in the case study, and effectively determines the BESS rating factors.

Hybrid DR generation:

This scenario includes increasing PV penetration levels and maximum rated BESSs, similar to Figure 1.1b. The proposed power management algorithms govern optimal power flow, controls BESS power cycles, enforces peak demand reductions, effectively utilises surplus energy, and ensures overall DR equipment operational synergy for load profile advancement.

1.3.2 Case study

Load profile impacts and conclusions from the modelled profile simulations will be implemented within an actual reticulation network to study the effects of integrated DRs. The network design of the mixed-use reticulation network, within a well-known South African municipality, will be based on PEPs and standards, with model parameters based on typical network topologies and practical electrical equipment ratings.

The simulation results and electrical parameters of the DR reticulation network (Figure 1.1b) will be compared to the traditional base case design (Figure 1.1a) and evaluated to grid-code connection standards. From the newly proposed design methodologies and results obtained the research questions and objectives will be evaluated and reviewed to provide a load profile estimation baseline within a modernised DR integrated reticulation network.

1.3.3 Evaluation of study

The study will be logically constructed through a valid approach. The hypotheses will be tested through simulations and practically confirmed on real world data to determine the effects of DRs integrated within reticulation networks. Independent variables to test the various hypotheses will include zoning types, load ADMDs, PV DG penetration levels, sizing and operation of BESSs, and the selected power flow management control. Dependent variables will be power flows, power losses, voltage profiles, and network parameters such as coincident demands, load factors, and reactive power requirements. A traditional reticulation design (without DG capabilities, ES components, and internal power control) will be used as a control for comparative analysis. Mills Causality method of concurrent variation (Changeable PV penetration levels and ES control on load flow, voltage profiles, and demands), method of difference (energy control on optimised storage), and method of residues (traditional design for comparative study) will form the basis of the study. From the dependent variables, simulation results, and the practical study, a sound argument will be made through load profile modelling on the effects of PV DG, ES, and power control.

The study will show the effects of PV DG and BESSs on commercial and residential zones, but does not include other zones such as heavy industrial, retail, educational, etc. The results and methodology provided in the study can be used as a hypothesised model for any unstudied zone and can be replicated in a similar manner. The results will identify to what degree the hypotheses can be made theory for an optimised and modernised reticulation network load profile design that includes DRs, load sharing capability, and conceptual power flow management control algorithms.

1.4 RESEARCH GOALS

The unavoidable impacts that high-penetration integrated DRs (PV DG and/or BESSs) will bring to South African reticulation networks remain unstudied and will result in unforeseen or detrimental electrical consequences in voltage regulation, current flows (losses), powers, fault levels, power factors, and load factors. These changes require a revised time-based approach to original planning methodologies, network designs, and grid operation to incorporate the various new aspects and additional variables that BESSs, inverter-based PV DG renewable systems, and power control will bring to electrical networks, starting from load profile analysis.

The time-based operational load profile changes that integrated PV DG, the different tactics to BESS technology and operation, and the combined DR system with optimised power flow control will be evaluated from first principle concepts that include software simulation optimisations and case study verifications. Increasing levels of integrated DRs will be modelled to include seasonal (high demand, low demand) and daily (weekday, weekend) changes on the two main distinctive load profile forms in a time-based analysis to determine the upper DR penetration limit irrespective of feasibility recommendations. A conceptual integration power flow control algorithm will be developed with the focus on DR equipment and grid integration synergy for the advancement of the overall network and lowering upstream network dependencies.

Other factors not directly related to DR reticulation network planning, such as DR protection topologies (well covered in existing guidelines and literature), accurate statistical consumer demand profile estimations, power quality and dynamic studies (such as frequency response and harmonics [25]) do not form part of this study and should be evaluated as the next step in grid integration to the acceptance of the local grid code compliance standards.

Critical parameters that will be evaluated for a permanent reduction of the POC maximum demand are the different approaches and advantages that BESSs can bring to network integration, PV DG network support, the impacts of reactive power, load factor improvements, utilisation factors, voltage regulation, and fault level contributions through a conceptual power flow control algorithm to ultimately combine and enhance integrated DRs and grid synergism for a modernised reticulation network design.

1.5 RESEARCH CONTRIBUTION

The concerns and uncertainties that integrated DRs and power flow control will bring to reticulation network designs are addressed by simulating the individual key-concepts and impacts that increasing levels of integrated PV DG, BESS, and the combined DR system will have on typical network demand profiles. Load profile integration modelling will define the conceptual power flow control algorithm for DR synergy and will determine the maximum DR penetration limits for the modernisation of reticulation network design methodologies.

The modelled DR load profiles include integration within the two main distinctive load profile forms typically found within reticulation network designs, namely non-domestic/commercial (weekday midday peaks and low weekend demands), and domestic (morning and afternoon peaks with lower midday demands) in seasonal (high demand, low demand) and daily (weekday, weekend) profile changes as required for any renewable integration study, which is not considered in traditional methods.

The DR integration methodology, DR penetration limits, network impact assessment, and the developed power flow control algorithm will provide a crucial background when revising traditional design methodologies, planning strategies, and feasibility study expectations by highlighting core DR design considerations for integration benefits (while limiting integration drawbacks) and the necessity of time-based (quasi-dynamic) profile studies.

Network advancement and financial benefit through DR integration will encourage a wider adoption of higher rated internal network developer driven renewable generation and energy storage investment. This will provide integration benefits to both internal/developer/end-user and external/utility networks through permanently reduced load-side maximum demands combined with lower peak period demands in preparation of a future smart grid system. On a more practical level, the approach followed motivates the inclusion of DR integration in service agreements, provides an alternative for new developments within constrained/overloaded upstream networks, and offers initial BESS and PV DG ratings for preliminary MFS documentation prior to EPC tender stages and detailed design.

1.6 RESEARCH OUTPUTS

From the research conducted and the results obtained, a journal article with the title of “Time-based Analysis of Distributed Resources in Load Sharing Reticulation Networks” was submitted for publication. This article details the modernisation and additional time-based design considerations required within DR reticulation networks to fully synergise integrated PV DG and BESSs as a combined DR system managed by the conceptual power flow control provided. Enhanced load profiles, with permanently reduced system maximum demands, are highlighted to provide a DR integrated design baseline for the technical and legislative advancement of electrical networks.

1.7 DISSERTATION OVERVIEW

Chapter 1 provided the introduction and baseline of the study by defining the problem statement, the study objectives, the approach that will be followed, study goals, contributions, and the research outputs.

Chapter 2 provides the literature study and focuses on the body of knowledge for the network integration of DRs, defined as a combination of PV DG and BESSs. It was found that many advantages can be achieved with correct integration, but that additional variables must be considered to prevent network complications. The significance and advantages of DR systems, network load demands, load profiles, PV penetration levels, BESSs and control, tariff structures, and levelized energy costs are all included to provide a full supporting background for the study. It was found that zone dependent load profile forms will play an integral role in integration studies, and that time-based load profile changes should be evaluated as a first step for optimal integration.

Chapter 3 provides the load profile studies and the initial DR profile simulations. This includes the theoretical and practical approaches for determining load profiles. Simulations include the impacts of BESSs (including the different approaches to BESS operational power control schemes) and PV DG with operational limits. Following the changes that BESSs and PV DG can bring to traditional load profiles an optimised power flow control algorithm is created for the efficient and synergistic integration of both PV and ES as a complete DR system, forming a baseline for the case study.

Chapter 4 provides the case study verification by implementing the DR limits and control from Chapter 3 within a real South African network. This includes traditional reticulation design (for comparison), BESS-only integration (for negligible PV generation capability and determining BESS sizing), and full DR integration with control (BESS operation with maximum PV generation capability).

Chapter 5 provides the discussion of results from the load profile studies and operational control (Chapter 3) and the case study (Chapter 4) by providing the main observations, comparisons, implications, acknowledgement of limitations, and recommendations.

Chapter 6 concludes the study by summarising the findings and highlighting the key considerations and recommendations for the future integration of DRs (BESSs and PV DG) within reticulation networks.

A detailed chapter overview, based on the Scientific Method, is shown in Figure 1.2.

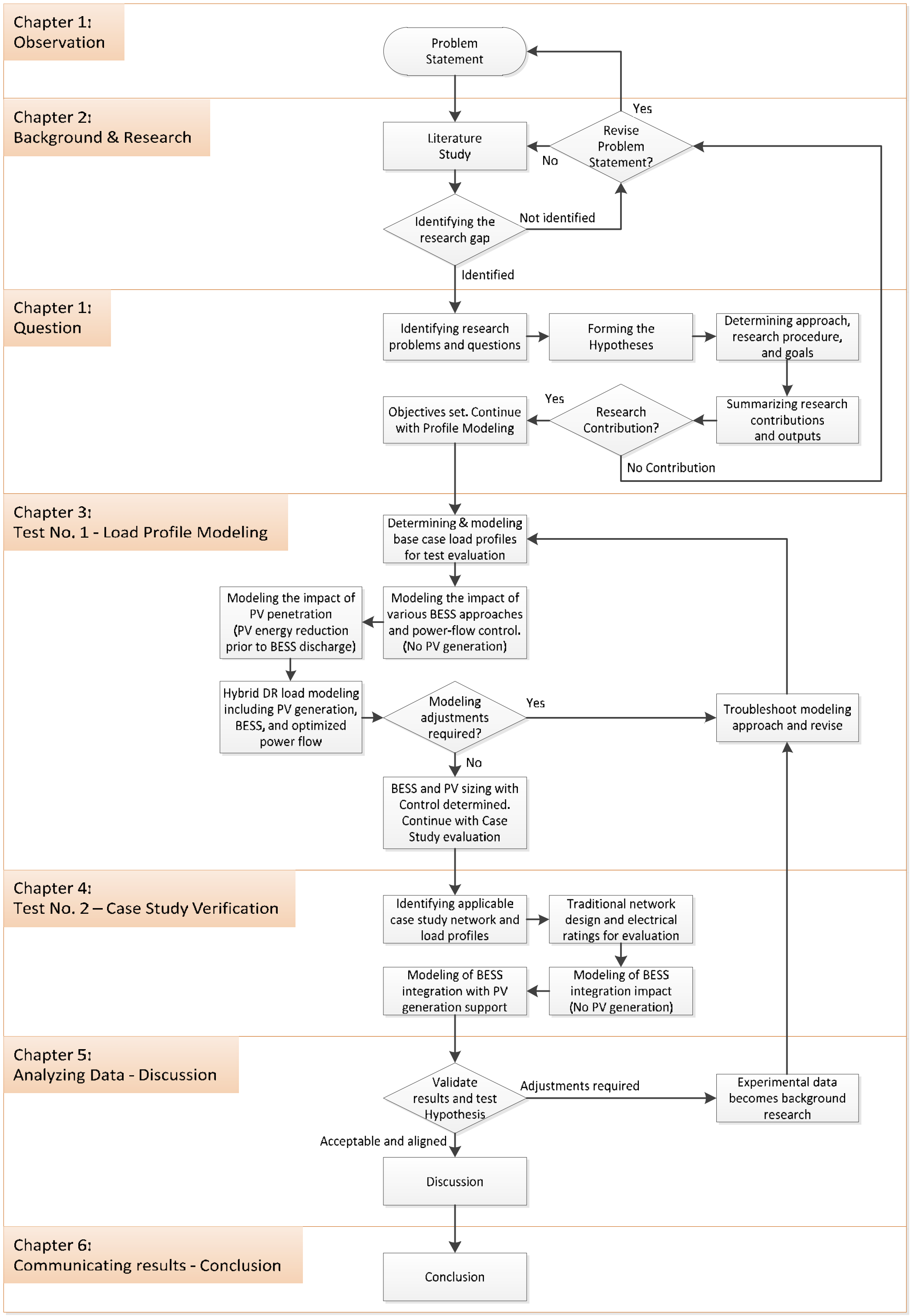


Figure 1.2. Chapter overview based on the Scientific Method.

CHAPTER 2 LITERATURE STUDY

2.1 CHAPTER OVERVIEW

The Chapter provides the Literature Study and sets the framework/baseline for the following chapters.

Section 2.2 provides the status, relevance and importance of PV DG and ES technology within electrical networks. Section 2.3 highlights the advantages that DRs can bring and motivates the integration thereof within electrical networks. Section 2.4 provides the background on load profile estimations and the fundamental role that load profiles will play within optimal DR integration studies. Section 2.5 discusses the various approaches to load parameter estimations for the two main distinctive load profile types within reticulation network designs. Section 2.6 discusses the various approaches and limits of PV generation systems and the impacts on load profiles. Section 2.7 discusses ES advantages, the importance of power flow management/control, sizing, various discharge approaches, and general technology alternatives for BESSs. In Section 2.8 financial considerations are discussed (from a South African perspective) that include energy tariff structures and levelized energy costs, forming the backbone of basic cost comparisons and financial optimisations.

2.2 DISTRIBUTED RESOURCES IN ELECTRICAL NETWORKS

DR (DG and ES) advancements are vital for the development and practical implementation of future smart grid systems [32], [39]. This correlates with the recent shift observed in power generation from conventional to inverter-based renewable energy sources in the global effort towards decarbonisation, driven by environmental concerns, fuel source depletion, increasing utility tariffs, and the continuous demand for more electrical energy [21]. DG systems are broadly categorised into renewable and non-renewable type sub-groups [32], [41], [42] with electrical ratings (ranging from 1 kW to 100 MW) well defined for implementation [43], [44].

Energy generation from global renewable sources is predicted to increase from 23% in 2010 to 34% in 2030 [45], with renewable systems installed in the US tripling within the last decade [46]. Renewable energy systems (led by solar generation) are the fastest growing generation technology type meeting more than 70% of global generation growth [47]. Since 2009, global investments have favoured PV power installations over wind power as PV systems are continuously becoming more feasible and practical not only for large applications, but also for small-scale end-users [21]. The expansion of DG will contribute to almost 50% of global PV capacity growth from 2018 to 2023 [17] with a similar high-growth pattern observed within South African PV markets [48] with NSP status statistics indicating a 350% yearly increase in installed rooftop PV capacities, rising from around 983 MW to 4.4 GW between 2022 to 2023 [14]. ES (seen as the “holy grail of renewable energy integration” [49]) plays a crucial role in DG system and network support [50], forming a vital counterpart requirement to the seamless grid integration of renewable systems. The integration of ES will play an increasingly significant role in the design and planning of reticulation systems [17], [32], especially with the growing prevalence of MV connected MWh-rated BESSs as supported by larger installed end-user PV DG systems, unreliable utility supply, increasing utility energy tariffs, superior operational control, and levelized costs approaching those of conventional generators.

Network stability depends on the transient stability state and the ability to recover to a steady state after a fault disturbance. The integration of DRs (a fault contributing source) introduces additional stability complexities that must be addressed before implementation [51]. This includes evaluating system stability during dynamic contingencies (faults, switching, load changes) [21] and assessing the system impacts to ensure stability from multiple integrated DR sources [52]. High network presence of inverter-based energy sources (such as grid-following PV systems) will reduce grid inertia, which should be reinforced to avoid frequency drift. Authority grid codes [34], [35] therefore mandate extensive pre-installation simulation verifications (static and dynamic), followed by commissioning validation, to be provided within a GCC report prior to the connection and operation of any independent generation or storage source impacting external network parameters.

Traditionally, grids are designed for radial operation or unidirectional power flow and follow a standard procedure for phase overcurrent, neutral/ground, and earth fault protection schemes coordination and cascading settings. Increased DR penetration within electrical networks will result in source and load nodes becoming mixed, forcing power flow to become bi-directional [39], changing distribution feeder characteristics to that of a transmission system, and requiring protection equipment modernisation for safe operation. Protection concepts with the implementation of DRs are more demanding compared to the traditional one-way radial systems in terms of coordination, communication [53], desensitisation, and bi-directional functionalities [54].

DG protection can be sub-categorised as feeder protection (substation-side) and interconnection protection (load-side). Feeder protection includes (but not limited to) dynamic fault level adjustments (from the additional sources of generation connected to the network), bi-directional power flow capabilities, and auto reclosing operations to coordinate with the interconnection protection system [39], [55]. Interconnection protection includes the use of specific DG integration transformer types [53] required for protection and grounding, voltage control, and fault current magnitudes [54]. Interconnection protection also includes (but not limited to) islanding management [56], synchronisation, frequency and voltage drift, power flow protection, auto-reclose adjustments, and phase unbalance detection.

IEC 61850 compliant IEDs can transmit protection statuses via GOOSE communication and adjust protection settings if communication infrastructure is available [40]. Modern

IEDs with communication, voltage, frequency, directional operation, embedded synchro-check functionality, inrush current settings (presence of the 2nd harmonic with the reconnection of DG sources), and phase balancing have been demonstrated to provide sufficient network protection for a DG integrated network [57]. Protection elements form a significant part of DG integration, are well covered within literature, and can be applied to reticulation networks [39] in addition to the South African grid-code requirements [34], [35]. The levelized cost of energy in South African networks is also well covered within completed projects and literature [58], forming a financial feasibility baseline for future DG network LCOE and feed-in tariff calculations.

2.2.1 Cybersecurity and Data Management

The operation of DRs requires advanced communication frameworks (such as smart grid technologies and IoT devices) that introduce significant cybersecurity and data management challenges. The increased connectivity and complexity of these systems render them vulnerable to cyberattacks, as multiple entry points are created by connected devices and communication networks that can be exploited, potentially causing power outages, infrastructure damage, or leaking sensitive consumer information. Robust cybersecurity measures, including access control, advanced encryption and anonymisation techniques, real-time monitoring, and threat detection systems are crucial to protect these networks and data from breaches, and ensure data privacy and security.

DR systems generate vast amounts of measurement and control data that must be stored, processed, and analysed through effective data management. Implementing big data analytics and machine learning algorithms could assist in managing this data, but it also requires substantial computational resources and robust data governance frameworks. Following industry-wide consistent standards and data exchange protocols for device interoperability is essential to ensure seamless communication between the different components of the network and to enhance the overall performance of interconnected DR sub-systems.

Cybersecurity and data management challenges must be addressed to ensure the secure and efficient operation of DR integrated networks. This requires continuous updates, collaboration with stakeholders, and advanced solutions to counter the evolving nature of cyberthreats and data vulnerabilities. Regularly updating security protocols, implementing robust measures and effective data management strategies, and adopting standardised protocols will mitigate risks and support effective integration and operation of DR systems.

2.2.2 Energy Markets and Policy-Making

As DR technologies continue to advance, the transition from centralised to decentralised systems introduces a new paradigm to energy production, distribution, and utilisation. This transition will reshape energy markets and necessitate a proactive evolution of flexible policy-making, requiring adaptive and forward-thinking approaches to maximise integration benefits while effectively managing administrative challenges. Modernised policies will enable a broader participation of smaller energy producers in the market, fostering increased competition that will lead to lower DR equipment and energy costs. Operational advantages provided by DR integration, such as enhanced flexibility from BESS operation, mitigate the inherent intermittency of renewables and allow for higher renewable penetration limits to stabilise energy markets and reduce price volatility.

DR integration necessitates revisions of existing regulatory frameworks and policies to address challenges related to interconnection, the establishment of fair and efficient net metering practices, and the development of incentives to promote the adoption of higher rated renewable energy and storage technologies. These regulatory adjustments are crucial for accommodating unconventional bi-directional power operation from diverse energy sources as introduced by complex DR systems. Incentive programs such as tax credits and subsidies for PV DG and/or BESS installations could further accelerate the transition towards more sustainable energy infrastructure.

2.3 THE SIGNIFICANCE OF A DISTRIBUTED RESOURCE NETWORK

A load sharing bi-directional power flow enabled network incorporating PV DG and ES DRs will provide various benefits when compared to a traditional one-way passive reticulation grid. With higher levels of DG penetration (and a reliable ES system) end-users and utilities (external networks) can both be provided with a more efficient, environmentally friendly, and reliable source of electrical energy. DR benefits can be categorised as technical, operational, economical [59], and environmental [43].

2.3.1 Reliability

Improved redundancy:

Energy source downtime (from maintenance, faults, sabotage) does not impact a DR enabled grid on a similar scale as with traditional grids as multiple sources of smaller generation capacities are present and distributed within the reticulation network [44]. For example, a single failure resulting in 40 MW unidirectional distribution substation capacity loss (such as Figure 4.2 HV/MV substation transformer bay failure) requires the network to source an additional 40 MW of power from reserves or shed 40 MW from the connected loads. In contrast, the loss of multiple smaller DG units spread across a load sharing network will have a reduced impact/risk, are more manageable due to smaller electrical ratings [21], and are supported by local ES systems to further improve end-user supply redundancy. DRs with advanced communication, load sharing, and load shedding capabilities (to prioritise specific critical loads) will provide the network with self-healing and self-sustainable potential which is a step towards smart grid operation [13], [60].

PV generation profiles will fluctuate considerably depending on temperature and other climatic factors [61], with cloud coverage lowering PV output by as much as 70%. Large, concentrated inverter-based PV energy parks will be influenced by weather considerably, especially if there is a high system demand. Other solar technologies, such as thermic CSP, can mitigate this risk by utilising salt storage capabilities (and improve system inertia through conventional turbine generation). Decentralising and distributing multiple smaller scaled renewable sources over a wider area within a network will improve generation diversification and lower outage risks, while minimising output fluctuations from local weather changes [62]. Generation inconsistencies can also be countered by BESSs and control.

Enhancing generation diversity:

Optimal integrated DG and ES components will complement each other by advancing the positives and reducing the individual technology negatives to bring a greater grid diversity for controllable load profiles to ultimately improve load ADMDs, network parameters, and overall equipment loading factors and losses.

The increased presence of grid-following inverter-based DG penetration within electrical networks will reduce the overall grid inertia and could lead to frequency drift. Enhancing generation diversity by installing grid-forming BESSs and/or reactive power compensation devices, grid-inertia and stability can be improved and strengthened to the benefit of the overall network to unlock full DR integration potential.

2.3.2 Network parameters

Power quality improvement:

Network voltage quality [49] and loss profiles [63] are improved through DG inverter control. The inclusion of ES could counter fluctuating power and voltage levels from renewable sources to a regulated output [64]. Inverter type DG reduces inrush currents and a significant result (as low as 0.3% [37]) in grid voltage fluctuation ranges can be obtained by maintaining the optimum voltage amplitude in reference to the measured load demand [65]. Advanced PV DG and BESS inverter technology could provide limited reactive power control capability (within P-Q operational envelopes, and without the loss of active power output) from oversized inverters with phase shifting capability, supported by reactive power compensator equipment such as FACTS devices.

Network Losses:

Traditional voltage improvements include the use of expensive OLTC transformers [63], line regulators on feeders, and grid switched inductors or capacitors for Voltage/var balancing [66]. The installation of inverter based controllable generation sources distributed close-to-load across a widespread area, provides advanced power and voltage capabilities through individual control that will lower I^2R power losses (through reduced power flow distances and voltage regulation) [25], [67] - [69]. A DG system with a rated output of between 10% – 20% of feeder demand can significantly reduce system losses similar to the installation of a capacitor bank system [63].

Reduced upstream capacity:

Upstream network capacities and power flows are reduced with optimised downstream DRs located close to end-users [44], [70]. This in turn reduces the utilisation factor of the intermediate distribution network [65], lowers the necessary installation/upgrade cost of upstream networks, and opens capacity for future developments. With a reduction in upstream capacity requirements, high penetration DR integration could provide the necessary support for remote area development or serve as an alternative to planned (but halted) developments due to upstream capacity being unavailable.

2.3.3 Economical

Upgrade investment deferral:

The installation of reticulation DRs can defer network upgrade investments (such as expensive upstream distribution substations) as local DG and ES now provide the network and downstream loads with the required supply capacities [60].

Operational costs:

Operational costs are reduced due to lower system losses [60], especially from strained upstream electrical systems and distribution network voltage step transformations [44]. A direct decrease in operational costs can be expected with smart DR power flow management control systems ensuring a permanent maximum demand reduction and limited use of grid energy in expensive TOU tariff periods.

Financial investment:

The continuous decrease observed in PV LCOE and the increase of utility demand and energy costs (as supported by project specific feasibility studies) have shown attractive developer DR investment opportunities. Commercial grid-tied PV systems are now expected to have payback periods in the order of 5 years or less. Technological advances in the ES field, reduced BESS costs, and the superior control provided by these systems will also contribute to attractive investments in the future, driven by the many benefits in both commercial and residential installations when combined with PV generation support.

A load sharing mixed-use distribution network can provide end-users with the option of selling surplus generated energy back into the grid in support of other supply demanding diversified consumers. This will be an added benefit to non-operational commercial and residential consumers (profiles with a low midday demand or solar profile mismatch) to fully utilise (or implement) high penetration levels of PV DG. The surplus generated energy can be used to generate additional income, increase the practicality of ES, and further reduce expensive system payback periods. At the time feed-in does not provide any major cost attractions for the installer but will remain an additional (however minor) benefit if supported by the local network supply authority.

Demand side management:

Generation and load balancing become crucial within variable (high or low) levels of available renewable generation, such as micro-grid or islanding operation. Demand Side Management provides the necessary control for network flexibility and stability and balances the DG, ES, Grid, and load counterparts. The implementation of smart demand control within user installed DR systems will enable the maximum demand to be reduced [17], shifted [23], or levelled [64] through power flow control (or load shedding applications) as seen by the billing utility. This will result in lower energy use for the consumer in peak times, reduced consumer energy costs, reduced utility losses, and provide a crucial backbone for future smart grid implementation [71].

2.3.4 Environmental

Reduction of land use:

A DR enabled network (with DRs located on end-user property) benefits the utility by reducing areas traditionally required for energy transmission or distribution upgrades owing to a decreased upstream capacity requirement provided by DG support and ES operation (energy arbitrage). This may also reduce the need for land use permit applications and environmental studies prior to construction. Additionally, PV DG systems are typically installed on unused surfaces such as building roofs or parking covers, and do not occupy large footprints of otherwise developable or protected land.

Advancing renewable energy:

DR integration promotes the implementation of renewable and environmentally friendly generation sources for grid augmentation [69]. A network supporting DRs and load sharing capability with a financially attractive feed-in tariff structure will motivate small scale users, that would not normally benefit from high penetration DG, to reconsider the installation of renewable energy sources. Opening the network and market for DG and ES integration will provide feasible opportunities that will drive manufacturer competitiveness and research into more efficient and optimised renewable alternatives, thereby promoting further development (and economic improvement) of renewable and energy storage system capabilities. The environmental benefits of DRs, particularly in terms of reducing greenhouse gas emissions and increasing the share of renewable energy in the energy mix, align closely with global environmental policy goals.

Reduced impact on nature:

The integration of renewable energy reduces the number of harmful emissions into the atmosphere in the effort to decarbonise the network [65]. Large renewable energy installations at distribution and transmission levels come with their own adverse effects, such as big PV plants eradicating large areas of surrounding *fauna* and *flora* and wind farms wiping out birds of prey and bat populations, both of which play important ecological roles. Small scale PV DG spread over a reticulation network over building surfaces does not have the same negative environmental effects.

2.4 NETWORK LOAD DEMAND

The total MV load demand (calculated at distribution level) is characterised as a composite load profile resulting from the summation of all diversified connected MV feeder load profiles. MV feeder demand is determined from the individual downstream non-residential or residential profiles connected to MV/LV distribution transformers. With increasing levels of end-user PV DG penetration and ES integration (which directly affect individual load profiles), load profile studies will become the baseline for evaluating DR network parameters.

Load profiles can be estimated from direct measurements through energy research initiatives [72], or determined from a “bottom-up” approach by calculating all individual LV connected loads and working upwards to distribution level [73], [74]. Additionally, ongoing research such as the NRS National Load Research Project (providing data from 1994 to 2014 for various South African residential classes by location [75]) can provide load profile predictions but remain a continuously evolving field of study. Direct real-time measurements are the most accurate representation of load profile data, but are difficult to obtain, only available post-development, are very user specific in terms of load type and load diversification, and will be different for all locations and building standards.

Load profiles and losses can be estimated statistically by representing distribution system LV consumers with Gaussian modelling [76], single residential demand profiles using multiple Gaussian parameters (to simulate both morning and evening peaks) [77], and multiple residential groups using Beta distribution parameters [78], [79]. Beta distribution can be verified with the “bottom-up” method and was shown to be the most accurate when compared to other approaches [80]. Simulation baseline profiles can be estimated by scaling and adjusting traditional load profile forms to ADMD maximums (Section 2.5) or measured data to determine load alterations, design parameter changes, and general impacts of integrated DR (DG and ES) systems [23], [33].

2.5 ESTIMATING LOAD DEMAND

To investigate the impact of PV penetration and ES integration within reticulation systems, the traditional methods of approaching load profiles for the different types of load classes should be considered. Load estimations are used in long term 20 year NMPs, shorter 5 year NDPs, and general short term 2 - 3 year project planning [10]. Demand calculations form a crucial pre-development requirement for engineering technical service reports and municipal service agreements that determine the electrical connection size (notified maximum demand or authorised capacity) and the amount of bulk contribution costs (R/kVA) to be paid by the developer for upstream utility upgrades.

Load estimations are fundamental for electrical planning and loading studies, equipment sizing, and determining load diversity between domestic and non-domestic load types. While it's possible to estimate the expected 24-hour load profile for the main types of consumers, the actual profile and maximum demand (or peak) remain unknown without direct measurement considering behavioural differences between similar zoned consumer types [81]. Simply adding the maximum demands of all consumer types will yield an over estimation of the connected load and eliminate the effects of load diversity that will result in the illusion of insufficient upstream capacity, overpriced or unnecessary electrical infrastructure, senseless no-load losses, and overpaid bulk contribution costs. In reticulation networks the main load profile types are Residential, Industrial, and

Commercial (Business) type loads [81], [82], with specifics defined in the development Conditions of Establishment that includes zoning type limitations or other restrictions.

2.5.1 Residential loads

Residential (Domestic) load profiles characteristically exhibit morning and afternoon load demand peaks with a lower midday demand. Several publications have addressed residential load modelling [77] - [79], and can be modelled as constant impedance or constant power type loads [83]. To determine typical South African residential load profiles, various load and sociodemographic data were collected over the period of 1994 to 2004 (consisting of over 618 million load readings) and analysed from 2005 to 2006 as part of the NRS 034 domestic load research project [84]. The non-linear hourly load model was found to be dependent on household demographic, income, floor area, location, time of day, and seasonal changes (temperature and rainfall) with winter demands shown to be the highest. The floor area of higher-income classes has a more significant effect on measured demand when compared to lower-income households with a similar floor area. Other factors include the availability of alternative fuels and the number of occupants [84]. These and similar studies highlight the presence of multiple variables that need consideration when attempting to predict residential load profiles, shifting engineering design to intricate statistical analysis.

Two approaches to residential load estimation in reticulation designs can be considered, namely the Probabilistic approach (Statistical) or Deterministic approach (Specified ADMD and Diversity Factor).

Probabilistic approach:

The statistical approach to load modelling has proven to be the most accurate due to the inclusion of load diversity [85]. This approach has found that maximum demand load data can be characterised using the beta PDF parameters when measuring similar residential consumer groups [86]. The PDF statistical parameters accurately describe the demand profile skewness of different load classes, each dependent on alpha, beta, and connection circuit breaker size values. Based on the beta model, a LV residential feeder analysis framework was developed specifically for South African networks [87], accepted by the AMEU, and included in residential feeder design as specified in the NRS 034 tables [11]. Table data include consumer class, income range, and other load parameters.

Deterministic approach:

Traditional design procedures and PEP use the average value of stochastic load peak demands [88]. At system peak, the load demand is referred to as the grouped system ADMD. The maximum demand of residential zones (at MV distribution transformer level) can be estimated as a function of diversity and coincidence factors arising from the number of units and the ADMD area factor. It can be shown that the equivalent ADMD per residential unit will decrease up to an asymptote with an increasing number of grouped units due to load diversity. Conversely, with a reduction of units (and the loss of diversification) the stochastic nature of single loads becomes more evident, and a diversity correction factor should be introduced. South African guidelines for load figures are tabled in the NRS 034 specifications and subcategorised into consumer class, ADMD, load factor, yearly energy consumption, unit density, stand size, and load density [11].

South African property zoning categorises residential units as residential Type 1 (One or two dwellings per erf, such as full title housing), residential Type 2 (10 to 20 dwellings per hectare, such as cluster housing and townhouses), residential Type 3 (21 to 40 dwellings per hectare, such as smaller cluster housing and townhouses), and residential Type 4 (41 to 120 dwellings per hectare, such as apartment units) [89]. National standards (SANS 10142 [90]) provide guidance and a calculation methodology for determining residential ADMDs in a “bottom-up” approach which are also typically used for Eskom residential connection applications. The City of Tshwane region (Pretoria) estimates the load for residential Type 1 and Type 2 units as a function of the specified area factor (function of ADMD) and breaker size. The maximum demand of residential Type 3 and Type 4 developments are estimated using the council load formula as a function of the total connected units [91]. The City Power region (Johannesburg) estimates all residential maximum demands from unit area sizes [92]. Other residential/domestic type loads identified in the Conditions of Establishment (such as guest houses, hostels, etc.) are individually specified within supply authority load estimation guidelines.

Site measurements have indicated a significant reduction in the ADMDs for residential Type 2 to Type 4 units following the introduction of solar geysers and gas stoves, and can realistically be estimated at 5 kVA or less per unit (2.5 kVA per unit for large densities). Residential Type 1 units can be estimated at 7 kVA per unit or less depending on size and alternative sources of energy installed.

2.5.2 Commercial and Industrial loads

South African property zoning categorises the two main non-residential (non-domestic) zones as Commercial (Business) and Industrial [89], characteristically having a high midday demand in operational daily load profiles. Reticulation network commercial and industrial zones can be modelled as a combination of constant impedance and constant power type loads [83]. Commercial Type 1 to Type 3 are defined for general business with retail and shopping centres. Commercial Type 4 is defined for corporate office parks with or without residential use but exclude other retail operations. Industrial zones can be defined as industrial Type 1 to Type 3 that include warehouses and manufacturing ranging from normal storage depots (Type 1) to specialist workshops and mini-factories (Type 3) or similar. Additional and specific zoning type limitations and restrictions are defined within the individual development Conditions of Establishment.

To determine the maximum demand at MV level, supply authority standards specify a constant power ADMD per maximum potential floor area (kVA/100 m^2). The approved floor area is calculated from the FAR/FSR as specified in the Conditions of Establishment. Examples of constant power ADMD per usable floor area are estimated at 8 kVA/100 m^2 for business/commercial and 2.5 kVA/100 m^2 to 4 kVA/100 m^2 for industrial within the City of Tshwane region (Pretoria) [91]. In the City Power region (Johannesburg) office parks are estimated at 8 kVA/100 m^2, heavy industrial/commercial at 6 kVA/100 m^2, and light industrial/commercial at 4 kVA/100 m^2 [92]. ADMD calculations are done at MV level and include internal loads diversity (which are typically designed internally from 11 kVA/100 m^2 to 14 kVA/100 m^2, with some exceptions such as fast food or other heavy industrial areas). Other non-residential zones identified in the Conditions of Establishment are individually specified within the supply authority load estimation guidelines and can follow a similar ADMD per usable floor area estimation or be allocated with a fixed maximum demand connection circuit breaker.

2.5.3 Actual readings and the impact of energy efficient buildings

The global efforts to reduce carbon footprints have resulted in revised South African building regulations to enforce and improve “Energy efficiency and energy use in the Built Environment” [93], [94]. These regulations, along with similar initiatives, encourage all new developments to prioritise energy efficient building materials and integrate alternative energy sources, particularly for heating purposes. The continual rise in utility energy tariffs also motivates financially conscious consumers to use energy more sparingly and to personally install energy efficient counterparts. All these factors contribute to an increased motivation to adopt energy efficient equipment and alternative energy sources, resulting in an overall reduction of development energy consumption and maximum demand.

Electrical load estimation guidelines remain unchanged and outdated (such as SANS residential ADMD estimations including obsolete lighting technology [90], even if LEDs are predominantly installed and CFL technology expected to be limited in the future [95]), resulting in overestimated but supply authority enforced ADMD values used in network designs. Field readings, however, support lower practical ADMD values, indicating that the South African electrical load estimation guidelines/standards should be updated to reflect a more realistic electrical network. Residential Type 3 and Type 4 site readings indicate practical ADMD values considerably lower than the estimated demand, occasionally reaching levels below 1.5 kVA per unit (at MV level) with the inclusion of gas and solar heating. Commercial load measurements have shown up to a 35% reduction of load demands when compared to estimated load calculations.

Metering data showed that COVID-19 lockdown has resulted in a further 15% (minimum) demand reduction within commercial loads. New working-from-home normalities will also have the potential to drastically alter both commercial and residential load demand estimations and load profile forms from the expected.

2.6 PV DISTRIBUTED GENERATION

PV DG penetration will change network parameters that include coincident demand, demand factor, coincidence/diversity factors, and equipment (lines, transformers, cables, switchgear) utilisation factors by reducing grid energy consumption up to 37% [96] and time-shifting individual load maximum demands [23]. Load factors are improved if the PV generation profile reaches the load maximum demand with loss factors (being a function of the load factor) following in a similar way [97].

The maximum PV penetration rating can be defined with limitations set out in the NRS 097-2-3 standard [36] or specified as a percentage to the load maximum demand [23]. Studies investigating the impacts of PV DG on existing networks (or renewable design verification) [33], [96], will simulate PV ratings to the NRS 097-2-3 standard by limiting PV generation to 25% of the NMD for all shared LV feeder consumers [36]. Additionally, another NRS 097-2-3 requirement states that SSEG should not exceed 15% of the MV feeder peak demand. By complying to the NRS 097-2-3 standard voltage variation is kept below 1% for all conditions [33]. Studies investigating the impact of worst-case penetration scenarios (as done in this study) will follow the ratio of PV DG penetration to the load maximum demand approach.

PV DG integration will have different network impacts resulting from individual load profile forms and general load irregularities. Study load profile models should be selected to represent seasonal and daily changes (measured in hourly intervals or less) to simulate realistic network impacts from seasonally affected PV generation variabilities. Studies utilising load profile data determined from yearly site measurements and growth factors will provide a more accurate representation of integration changes [22], however, can also be estimated using typical (standardised) load profile forms scaled to predicted maximum demands if real profile data is unavailable [23], [33].

Increasing PV DG penetration in a commercial network has shown that low levels of penetration will not significantly alter load parameters [23]. The commercial load factor will improve up to a specific value (with PV DG lowering the maximum demand) but will worsen if the maximum demand remains unchanged with increasing levels of PV penetration. PV DG in residential networks does not traditionally contribute to a reduction in load maximum demands as the PV generation profile does not reach the late afternoon load peak, and thereby contributes to a worsening load factor.

Higher load demand draws higher current, resulting in greater power (I^2R) losses and a lowering POC voltage profile. An increase of PV penetration will lower the load demand during PV active times, reduce network losses [98], free up transformer capacities, and increase voltage profiles [3], [22], [33]. Load profiles with low midday demands and high PV DG surplus could result in voltage profiles increasing beyond allowable limits.

Weekend profiles should be considered with integration, where non-operational commercial load will be much lower and residential morning load peaks will shift to late mornings or early afternoons. Non-operational commercial feeders indicate the possibility of high PV DG surplus levels that will result in voltage profile rises. Residential weekend load profiles are more practical for PV installations (due to a higher midday load demand when compared to weekday profiles) and could potentially benefit from commercial PV generation surplus, signalling possible network feed-in benefits brought forward from mixed-use network load diversities.

The integration of PV DG into reticulation networks requires additional inputs and design requirements that must be replicated in integration studies and validated through time simulations, in contrast to standardised network design methodologies that only consider winter (maximum) load demand data.

2.7 ENERGY STORAGE AND CONTROL

Coupling renewable sources with ES is recommended but includes additional integration and optimisation challenges [99]. ES mode of operation through power management control includes, load support when the preferred source of supply (renewable or utility) is insufficient [64], regulation of variable renewable generation, load levelling, peak shaving, and energy arbitrage to provide supply redundancy and energy/demand cost savings [33]. Additionally, BESS integration (with advanced power control) can contribute to greater grid stability by providing black start capability, reactive power control, voltage profile control [32], [64], and system reliability improvements such as spinning reserve (a recommended requirement with intermittent renewable installations), and an increase in synthetic grid inertia (frequency control) lacking in high penetration grid-following inverter systems.

2.7.1 Energy storage types

The main components for BESSs include enclosures/containers and foundations, earthing, PCSs (and transformers), modular storage systems, fire suppression systems, HVAC, cabling (MV and LV, AC and DC), terminations, circuit breakers (and other protection), along with battery, energy, and SCADA management and control systems.

Lithium-ion electrochemical systems are considered a commercially matured technology and expected to become the highest in-demand ES type in the following years. Lithium-ion systems operate within well-defined conditions over a vast range of trusted time-tested applications ranging from portable electronics, electric vehicles, aerospace, up to large-scale grid applications. Lithium-ions are used as the charge carrier between the anode (typically graphite) and cathode (that defines the different Lithium-ion sub-types) during operational cycles typically in the ambient operating temperature range of -30 °C to 45 °C (pending derating factors). Lithium-ion BESS costs are projected to greatly decline in the next decade, heavily supported by the growing electric vehicle market with core technology advancements and reliability demonstrations carried over to stationary systems.

Many grid installations have proven bankability of modular Lithium-ion ES assets resulting from high system performances, efficiencies, and energy densities that are combined with years of experience that are offered by numerous trusted competitive ES integrators. The technology, however, raises many environmental and ethical concerns sprouting from material sourcing and complex/costly end of life recycling processes. Lithium-ion requires fire suppression and active cooling, ventilation, and air-conditioning (HVAC) that will directly impact the round-trip efficiency of the system. Technical Lithium-ion drawbacks to be considered include fire and safety risks under mechanical damage, electrical strain (example short-circuit, over-charge) and high temperature operation, and the continuous degradation of system performance (to be continuously augmented) throughout system lifetime and operational cycles.

Expected to emerge as a Lithium-ion storage alternative, specifically within long duration energy storage applications, are Vanadium-redox flow systems. Tank stored electrolytes as the energy storage component are pumped to a power cell to accommodate the ion-exchange reaction through a membrane. This provides flexibility in capacity upgrades by increasing the electrolyte volume, resulting in marginally low upscale costs if required. An additional advantage provided by the electrolyte system is the instant recharge by replacing the reactant container ultimately adding to system redundancy. The safe DoD, number of cycles, and system lifetimes are significantly higher than Lithium-ion systems and are able to operate passively for longer periods without the loss of storage capacity. The round-trip efficiency and energy density, however, are lower when compared to Lithium-ion systems, resulting in up to four times higher footprint and weight requirements. Flow systems are characteristically safe as highly reactive or toxic substances are not used and the active materials are not stored together with the reactive source. As electrolytes are water diluted, heat generation does not present the same fire hazard as with temperature sensitive thermal runaway prone Lithium-ion systems. The technology offers reduced ecological impacts through material acquisition and manufacturing and simpler end-of-life recycling processes. The technology is less developed for grid-augmentation (compared to Lithium-ion systems) and requires higher CapEx and OpEx due to additional mechanical equipment (such as pumps) required in the system but has been proven bankable in long duration discharge applications over Lithium-ion alternatives. With market presence increasing, recent technological efficiency improvements, and an expected reduction of costs, flow systems could have the potential to bridge the gap for inherently safe and consistent high penetration long discharge operation (such as peak shaving) in residential and commercial applications reinforced by longer discharge times, upgrade flexibility, extended lifetimes, and a reduced ecological impact (for a greener alternative), with sub-second responses not having any operational downsides.

Table 2.1 provides key comparisons (derived from available OEM datasheets) for selecting the preferred BESS technology type. The typical ranges shown are dependent on internal chemistries, manufacturing, and technology (such as chemical composition) sub-groups.

Table 2.1 BESS technology type parameter comparisons.

	Lithium-ion	**Vanadium-redox**
Discharge Range	Up to 8 hours	Typically, 4 - 8 hours (Up to 12 hours available)
Construction Type	Containerised, Modular	Containerised, Modular
Installation	Outdoor	Outdoor and Indoor
Roundtrip Efficiency	85% - 95%	70% - 80%
Lifetime Cycles	3 000 - 7 000 cycles	20 000+ cycles
Lifetime	10 – 15 years	20 – 25 years
Depth of Discharge	80%	100%
Energy to Weight	80 - 250 Wh/kg	10 - 130 Wh/kg
Power to Weight	200 - 2000 W/kg	50 - 150 W/kg
Energy Density	95 - 500 kWh/m^3	10 - 33 kWh/m^3
Response Time	Milliseconds	Sub-seconds
CapEx	300 - 450 USD/kWh	150 - 1 000 USD/kWh
OpEx	3% - 5% of CapEx	65 - 75 USD/kW/year

Not all ES types are suitable for all operational requirements, and BESS technology selection should be based on project specific variables such as, required application, discharge/recharge operation, financial feasibility, technical trade-offs, ratings and sizes, available area, climate, environmental factors, installation logistics, and safety [100], [101], as there is no “silver bullet solution” for all applications.

Considering factors such as mixed-load diversities, cost, policies, capacity limitations, and concentrated maintenance, an alternative approach could be considered by shifting smaller user-based distributed BESSs to a larger CES system [102], typically installed at HV/MV substations. Although CES systems have shown many advantages, this approach was not considered being in contradiction with current South African renewable market trends for the integration of ES inside reticulation networks [17], requires utility installations, removes distributed redundancy, requires larger system footprints, and shifts supply redundancy from the consumer back to the utility.

2.7.2 Mode of operation

Without proper power management and control even ideal ES systems (lossless with instantaneous discharge/recharge rates) can contribute to unwanted network conditions. These include high system losses (from unnecessary power flows), irregular voltage profiles, high energy costs (from high tariff charging), or maximum demand increases (from charging during load peak periods). Various research were done in the ES control, sizing, and management space [103] - [105], with the most practical and cost effective approaches found to be based on TOU energy arbitrage and maximum demand reduction.

Three main ES discharge approaches can be considered for TOU energy arbitrage in peak tariff periods [33]. The “full discharge” approach allows ES to discharge the full BESS rated output, independent of the local load, with surplus discharged power flowing back into the grid. Apart from being uneconomical, this approach will also result in the worst voltage fluctuations, proving that load sharing with uncontrolled ES presence can have a negative impact on network parameters. The “load following discharge” approach allows

ES to discharge up to the local load demand (without exceeding the maximum load limit) to prevent surplus discharge into the grid. Similarly, the third approach "conservative discharge", limits the maximum ES discharge to a specified percentage of the local load consumption to focus on maximising ES lifetime. ES discharge in a "load following" or "conservative discharge" approach will support the grid by improving the lower voltage profile in high network demand periods.

ES and power control will be responsible for a significant change in load flow during discharging and recharging periods, resulting in shifted load demands as seen by the POC metering profile. ES will not increase the cumulative amount of energy purchased from the grid, with the only (minor-) difference being BESS losses recuperated from the network during the selected recharge period.

2.8 FINANCIALS

The main financial drives for PV DG and BESS integration in internal networks are demand and energy cost reductions. Energy tariff timeslots are based on the NSP TOU schedules [15] with the individual tariff types (and linked conditions) dependent on the local supply authority. Supply authority tariff structures are based on the City of Ekurhuleni financial year July 2024 to June 2025 [106] in preparation for the case study of Chapter 4. The TOU energy tariff structure is visualised in Figure 2.1.

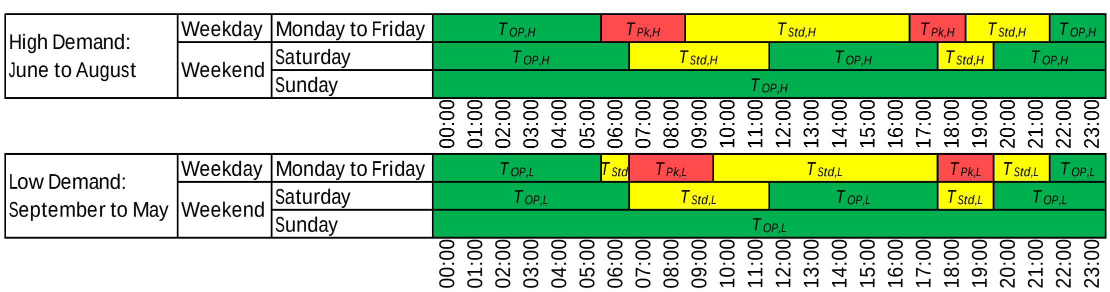


Figure 2.1. Yearly TOU energy tariff structure.

$T_{Pk,H}/T_{Pk,L}$, $T_{Std,H}/T_{Std,L}$, and $T_{OP,H}/T_{OP,L}$ are the specific supply authority high (H) or low (L) seasonal peak, standard, and off-peak tariffs in R/kWh. Demand charges include the NDC tariff (T_{NDC}, in R/kVA) based on the highest registered demand per connection point in a billing month and the NAC tariff (T_{NAC}, in R/kVA) based on the highest registered demand over a rolling 12-month period during peak and standard hours only. Additionally, specific tariff type fixed or other charges per month (whether electricity is consumed or not) will remain unaffected by DR integration apart from potentially allowing a complete tariff structure reassessment. In the high demand season (June to August) peak tariffing normalises to 284% and off-peak tariffing to 60% of the standard tariff amount. In the low demand season (September to May) peak tariffing normalises to 152% and off-peak tariffing to 79% of the standard tariff amount. These proportions indicate the focus areas where DRs will have the highest energy cost impact. Historical NERSA approved municipal energy cost increases were 13.07% (to 2019/2020), 6.23% (to 2020/2021), 14.59% (to 2021/2022), 7.47% (to 2022/2023), and 15.00% (to 2023/2024 [106]), suggesting consistent high increases to be expected in the future.

Levelized energy costs and levelized cost of discharged energy play a crucial role in determining project viability. The LCOE (PV generation energy) and LCUS (BESS discharge [107]) are estimated from feasibility studies to compare financial deliverables (such as the IRR and MIRR) and evaluate or revise prospective projects before construction. LCOE and LCUS take into account initial system costs and the NPV of total lifetime costs as a factor of the total lifetime energy yield (PV DG) or total energy discharge (BESS) of the rated system. Variables affecting the levelized cost over the equipment lifetime include (but not limited to):

- Initial project capital costs and investments.
- Financial inputs (Exchange rates, loan amounts, and interest).
- Operation costs (Land use or leasing of grounds, asset management, environmental and social responsibilities, maintenance, insurance, permits, and other operational related costs) calculated with estimated yearly inflation rates.
- Sub-equipment failure/replacement/upgrade costs within the project lifetime (Example, multiple inverter replacements within a solar installation or BESS capacity augmentations throughout the respective system lifetimes).

- Supply authority (or similar) connection costs.
- Total rated PV energy yield or total rated energy discharge from the BESS within the system lifetime (System capacity).
- Yearly system yield or discharge degradation factors.
- Charging and discharging losses (dependent on the type of BESS control).

The system income for payback period calculation over equipment lifetime includes (but not limited to):

- The applicable energy and demand tariffs (with forecasted cost inflation rates).
- PV DG income: Lower LCOE compared to grid tariffs, and demand savings.
- BESS income: Energy arbitrage and demand savings.
- Generated/discharged energy sales.
- Tax and other national/local incentives.

For PV installations the LCOE ($LCOE_{PV}$) can be calculated in (2.1) as,

$$LCOE_{PV,Y} = \frac{CapEx_{y=0} + NPV\left(\sum_{y=0}^{Y} OpEx_y\right)}{\sum_{y=0}^{Y} DG_{PV,y}} \qquad (2.1)$$

and for BESS installations the LCUS ($LCUS_{ES}$), specific to how the storage is practically operated, can be calculated in (2.2) as,

$$LCUS_{ES,Y} = \frac{CapEx_{y=0} + NPV\left(\sum_{y=0}^{Y} OpEx_y\right)}{\sum_{y=0}^{Y} ES_{Disch,y}} \qquad (2.2)$$

where Y is the projected project lifetime and y the operational year. $CapEx_{y=0}$ is the initial capital costs and $OpEx_y$ the operating (and other associated costs) of the system within the operational year. $DG_{PV,y}$ is the yearly generated PV energy of the system and $ES_{Disch,y}$ the yearly energy discharged from the BESS. Energy yield and energy discharge include yearly energy degradation and loss factors.

Levelized energy costs can decrease with increasing system ratings (if resource availability and installation costs remain constant) as installations take advantage of “economies of scale” and a more efficient use of available resources for a lower equivalent cost. However, while larger systems may offer higher energy capacities, they might not necessarily offset elevated installation costs stemming from potentially non-linear and disproportionate expense increases pertaining to resource limitations, land constraints, or other costs such as permitting, grid connection requirements, and maintenance. As a result, similar rated systems could have a notable difference in the levelized cost of energy, making it crucial to evaluate specific system cost-effectiveness and not extrapolate from other installations. Recent feasibility studies and industry tender submissions received in 2021 of similar rated projects, control, and within the case study municipal area have shown $LCOE_{PV}$ typically in the range of R 0.70/kWh - R 1.80/kWh and below the expected literature ranges published in 2020 market intelligence reports (for example 500 kWp systems [108]). BESS costs ($LCUS_{ES}$) can range from around R 3.00/kWh depending on the selected storage technology, ratings, and mode of operation. PV DG and BESSs are becoming cheaper per energy output compared to diesel generator alternatives with expected $LCOE_{GEN}$ (that includes fuel, maintenance, and yearly fuel increases) typically in the range of R 4.00/kWh - R 8.00/kWh.

Practical payback periods have consistently decreased over the years as utility energy costs continue to increase. A steady decline is also observed in levelized energy costs, supported by a more competitive market (decreasing overall system costs) that provides practical DR systems with increased efficiencies, higher energy outputs, and lower degradation aging factors as predicted within literature [4], [13], [16]. Feasibility studies for commercial applications typically estimate a payback period of between 4 to 8 years for PV installations and 6 to 15 years for low to medium penetration BESS installations. Residential PV (and ES) installations have a longer payback period due to the mismatch of the low midday demand and the PV generation profile, with the main drive being owner convenience and power redundancy provided in NSP load shedding periods. Practical supply logistics and market demand implications following COVID-19 (and other recent world developments unknown by industry and literature at the time) could in turn drive up costs from the predicted R 0.46/kWh $LCOE_{PV}$ in 2030 [17].

Surplus generated load-side energy can be supplied back to the grid and reimbursed at seasonal feed-in tariff $T_{FI,H}/T_{FI,L}$ (in R/kWh) if permitted by the local supply authority and tariff structure. Average South African FITs typically aligns with the NSP low demand standard energy tariff but could be higher depending on municipal tariff structure conditions and NSP network proximity. FIT structures can also be temporarily increased by local SSEG FIT incentives to encourage new applications [16].

There are three basic FIT schemes for internal network DR surplus generated energy external network feed-in. Scheme No. 1 and Scheme No. 2 applies to developments feeding into an external/utility network. Scheme No. 3 is applicable when feeding into private/internal networks. Scheme No 1, “Wheeling” or “Open Access Transmission”, allows surplus generation to be exported and distributed to other consumers through external networks (possibly owned by a different utility) for a greater network access. Energy credit can be based on a flat or TOU rate as defined by the local municipal supply authority conditions (example, City of Ekurhuleni Wheeling Tariff G [106]). Scheme No. 2, “Banking”, is currently only available to Eskom/NSP connections and utilises energy “Offset” (surplus energy feed-in being offset to energy used at the same TOU structure) and “Banking” (the carrying over of “banked” surplus feed-in energy not being offset within the month to the following month) structures to determine equivalent FIT costs or energy credits. Exported energy is essentially "stored" in the grid for future use, thereby offering a good rate of return. Scheme No. 3 (PPA) is for feeding into a private network with the owner managing a VPP. Tariff scales are determined as stated in the PPA (based on internal metering and market studies, usually as a fraction of standardised rates) and can result in good FIT scales pending internal negotiations and additional benefits.

The Cost Factor (CF) per unit value (R/kVA) is introduced as a function of the original load yearly maximum demand (MD_{Load}) to estimate the optimal integration level from a costing perspective. This simplified method compares load profile high-level cost impacts and savings potential as a function of different DR focal areas and trade-offs, levels of penetration, and power flow control, while also considering utility TOU energy tariffs and demand charges. As an illustrative and comparative tool, this should not be used as a substitute for more precise cost calculations and feasibility software alternatives provided (such as HOMER software). The yearly *CF* is calculated in (2.3) as,

$$CF = \frac{Cost_{DR,D} + Cost_{Grid,E} + Cost_{DR,E}}{MD_{Load}}. \tag{2.3}$$

$Cost_{DR,D}$ is calculated to include the cost variation resulting from the altered load maximum demand in (2.4) as,

$$Cost_{DR,D} = \sum_{n=1}^{12} MD_{DR,n} \cdot T_{NDC} + MD_{NAC,DR} \cdot T_{NAC} \tag{2.4}$$

where $MD_{DR,n}$ are the new monthly maximum demands of the system following DR integration and $MD_{NAC,DR}$ the new rolling yearly maximum demand after DR integration at the load POC (as seen by the utility). T_{NDC} and T_{NAC} are the network demand (monthly) and network access (yearly) charges per respective maximums.

$Cost_{Grid,E}$ is the grid seasonal energy costs based on the TOU structure of Figure 2.1 and is calculated as the sum of (2.5) and (2.6) which include network feed-in revenue (if applicable) as,

$$Cost_{Grid,E,H} = E_{Pk,H} \cdot T_{Pk,H} + E_{Std,H} \cdot T_{Std,H} + E_{OP,H} \cdot T_{OP,H} - E_{FI,H} \cdot T_{FI,H} \tag{2.5}$$

$$Cost_{Grid,E,L} = E_{Pk,L} \cdot T_{Pk,L} + E_{Std,L} \cdot T_{Std,L} + E_{OP,L} \cdot T_{OP,L} - E_{FI,L} \cdot T_{FI,L} \tag{2.6}$$

where $E_{Pk,H}/E_{Pk,L}$, $E_{Std,H}/E_{Std,L}$, and $E_{OP,H}/E_{OP,L}$ are the total energy from the grid in peak, standard and off-peak TOU periods billed at the applicable high or low seasonal tariffs $T_{Pk,H}/T_{Pk,L}$, $T_{Std,H}/T_{Std,L}$, and $T_{OP,H}/T_{OP,L}$. The total energy supplied back to the grid

($E_{FI,H}$/$E_{FI,L}$) is reimbursed at seasonal feed-in tariff $T_{FI,H}$/$T_{FI,L}$ if the supply authority and tariff structure permits.

The $Cost_{DR,E}$ term is calculated in (2.7) to include PV DG and BESS operational costs as,

$$Cost_{DR,E} = DG_{PV,y} \cdot LCOE_{PV} + ES_{Disch,y} \cdot LCUS_{ES} \tag{2.7}$$

where $DG_{PV,y}$ is the total yearly energy generated from PV DG systems and $LCOE_{PV}$ the LCOE for PV generation calculated from (2.1). $ES_{Disch,y}$ is the total yearly BESS energy discharged with the calculated LCUS ($LCUS_{ES}$) derived from (2.2) dependent on the mode of operation and the approach to cycle control. BESS energy recharge (including round-trip efficiencies) from the grid is included in (2.5) and (2.6), or included in (2.7) if recharged from surplus PV DG. A reducing *CF* indicates financial savings, whereas an increasing *CF* indicates financial losses. The *CF* estimation is based on profile energy use and load profile changes, and fixed monthly charges or similar (whether electricity is consumed or not) are not included as DR integration will have no impact.

To estimate future *CFs* a conservative yearly electrical energy cost inflation can be assumed to be,

$$Energy\ cost\ inflation\ (Year\ 1) = 10\%, \tag{2.8}$$

$$Energy\ cost\ inflation\ (Year\ 2+) = 13\%. \tag{2.9}$$

High energy inflation estimates are expected based on the planned increased energy purchases from IPPs and increasing carbon taxes. NSP generation constraints will result in the supply authority requesting more cost-reflective double-digit tariff increases from the year 2022 onwards [16].

2.9 CHAPTER SUMMARY

In this Chapter an overview of the Literature Study was provided to support DR network integration, determine the research gap, and to define simulation baselines.

In Section 2.2 the importance of DR integration was highlighted by concluding that PV renewables and ES systems will have an unavoidable impact in future networks and should be analysed. In Section 2.3 it was shown that DRs can bring many advantages, motivating integration for a modernised and independent network in support of a future smart grid system. Section 2.4 and Section 2.5 addressed the significance and various approaches to network load demand estimations. In Section 2.6, PV system integration network impacts and limits were identified. Section 2.7 summarised BESS integration advantages, highlighted integration considerations, discussed operational limits and the importance of power management and control, and provided a general overview of BESS components and technology alternatives. In Section 2.8 TOU structures, FIT structures, LCOE (PV), LCUS (ES), and energy cost inflation (to recent financial models) were discussed and concluded that significant utility energy and demand cost increases will further drive DR presence within electrical networks, reinforced by private developer investment. The Cost Factor (*CF*) is also defined as a high-level cost estimation comparison tool.

CHAPTER 3 PROFILE MODELLING

3.1 CHAPTER OVERVIEW

The Chapter provides the first principle mathematical estimations for typical reticulation network load profile types (seasonal, weekday and weekend), the impacts of BESS power flow control, and the effects of PV penetration to determine the limits and optimal power management control strategy prior to the Chapter 4 case study verification. The first principle/conceptual DR software tool developed from study findings (Addendum A) was used for all parameters and simulation results.

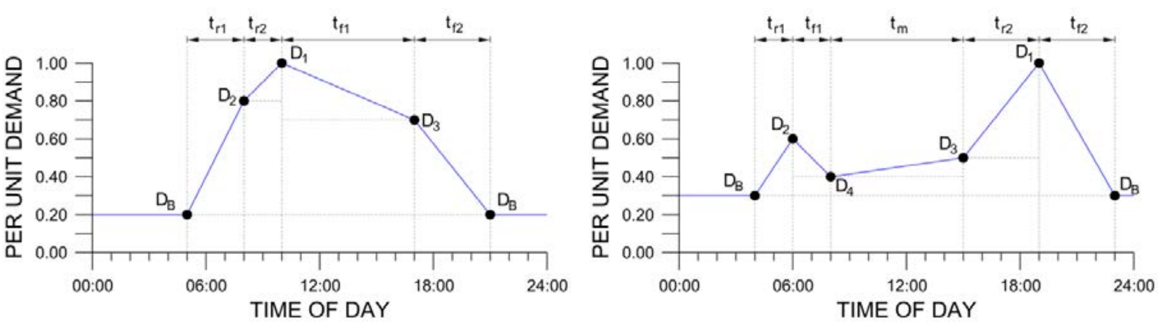
Section 3.2 provides a mathematical approach for estimating the per unit load profiles and load factor calculations. Section 3.3 presents the results of measured load profiles and reviews the impact of seasonal changes, the differences between weekdays and weekends, and the load power factor. This section also defines the load profiles selected for the profile studies and the Chapter 4 case study simulations. Section 3.4 specifies the BESS rating and sizing factors, defines the BESS simulation variables and control schemes, and simulates the differences, impacts, and benefits/drawbacks that the various approaches to BESS discharge and recharge possibilities will have on the selected load profiles. This section also provides a mathematical approach to estimate the maximum rated peak shaving BESS discharge possible and presents a mathematical tool for approximating the BESS levelized cost of discharge breakeven point. Section 3.5 specifies the PV system rating and sizing factors, defines the PV system simulation variables, compares two different PV penetration profile approaches (mathematical and software based), and proposes and simulates the integration of PV DG as a supplementary energy reduction support system. Section 3.6

combines the findings of Section 3.4 (BESS foundation) and Section 3.5 (PV DG support) for a permanent POC maximum demand reduction by defining the power control methodology of the combined DR system (BESS and PV DG) and provides the conceptual power-management control load-flow algorithms. This section also proposes the possibility and utilisation advantages of sectionalising the rated BESS capacity into primary and secondary subsystems. The findings of Section 3.6 determine the rating, sizing, and power control of the PV DG and ES systems that will be used for the case study verification in Chapter 4.

3.2 THEORETICAL LOAD PROFILE MODELS FROM FIRST PRINCIPLES

Load profiles form a crucial component in determining the impact of DR integration within electrical networks. To highlight key concepts, theoretical load profiles are estimated and modelled from first principles, followed by practical readings and findings in Section 3.3.

Figure 3.1 illustrates the characteristic and theoretical main load profile forms as expected from commercial and residential consumers, and visualises the diversification advantages that mixed-use load types will have on the overall network demand.



(a) (b)

Figure 3.1. Theoretical load profile forms with model estimation points.

(a) Commercial daily load profile. (b) Residential daily load profile.

Equation (3.1) states the magnitude constrains for selecting the demand profile points such that,

$$D_1 \geq D_2 \geq D_3 \geq D_4 \geq D_B \tag{3.1}$$

where D_1 is the maximum demand. Demands D_2, D_3, and D_4 represents the additional demand points in a descending magnitude order. Commercial demands D_2 and D_3 can be chosen as rising or falling demands. For residential profiles, D_2 is always selected as the morning peak demand, D_3 as the demand before the D_1 (maximum) peak, and D_4 as the demand after the first (morning) peak. D_B is the baseline demand for both consumer types.

From Figure 3.1a, hourly commercial time periods are selected with t_{r1} as the first rise time from the base demand to the first peak demand (D_2 or D_3, depending on magnitude). The time from the first rising/pivot demand (D_2 or D_3) to the maximum demand peak (D_1) is defined as t_{r2}. The time from the maximum demand (D_1) to the first falling/pivot demand (D_2 or D_3) is defined as t_{f1}. The period between the first falling/pivot demand (D_2 or D_3) to the base demand is defined as t_{f2}. Residential time periods are selected in Figure 3.1b such that t_{r1} represents the time from the base demand to the first peak demand (D_2), and t_{f1} the period containing the morning demand drop to midday start demand. The period t_m is between the two midday demands D_4 and D_3. For the second (highest) afternoon peak (D_1) the time periods are selected as t_{r2} and t_{f2} for the rise to peak and fall to base demand respectively.

Non-operational commercial profiles (such as weekend loads) can be modelled similarly with reduced D_1, D_2, and D_3 demand magnitudes and adjusted time variables. Residential weekend profiles will change with a shifted D_2 peak (to later in the mornings or early afternoons) and adjusted demand and time variables. Seasonal changes can be modelled similarly, with summer (South African low demand) maximum demand magnitudes for commercial loads ranging from 40% [96] to 92% [109], and residential loads ranging from of 40% [96], 50% [109], 63% [84], 64% [110], or 77% [111] of the yearly load maximum demand.

To optimise reticulation networks, the maximum demand should be reduced for an improving load factor (*LF*) defined in (3.2) as [97],

$$LF = \frac{\sum_{n=1}^{N} D_n \cdot t}{MD \cdot T} = \frac{\int_0^T D(t).dt}{MD \cdot T} = \frac{E}{MD \cdot T} \tag{3.2}$$

where *E* is the total energy utilised in kWh (represented as the area under the curve of the selected demand points, D_n), *MD* the maximum demand (or D_1 in Figure 3.1) with a decreasing value resulting in an improving *LF*, and *N* the total measurement points calculated by dividing the total period hours (*T*) by the measurement interval time *t* (in hours), all within the specified *LF* calculation time period. Commercial energy can be estimated using (3.3) as,

$$E_{Com} = E_{Com1} + E_{Com2} \tag{3.3}$$

where,

$$E_{Com1} = \frac{D_r(t_{r1} + t_{r2}) + D_1(t_{r2} + t_{f1}) + D_f(t_{f1} + t_{f2})}{2} \tag{3.4}$$

with D_r selected in (3.5) as,

$$D_r = D_2 \; or \; D_3 \tag{3.5}$$

whichever occurs first in the day as the rising pivot demand. D_f is selected in (3.6) as,

$$D_f = D_2 \; or \; D_3 \tag{3.6}$$

whichever occurs last in the day as the falling pivot demand. The last term of (3.3), dependent on the base/constant load of the daily profile, is calculated using (3.7) as,

$$E_{Com2} = D_B\left(T - t_{r2} - t_{f1} - \frac{t_{r1} + t_{f2}}{2}\right). \tag{3.7}$$

Following a similar approach, residential energy can be estimated using (3.8) as,

$$E_{Res} = E_{Res1} + E_{Res2} \tag{3.8}$$

where,

$$E_{Res1} = \frac{D_1(t_{f2} + t_{r2}) + D_2(t_{f1} + t_{r1}) + D_3(t_m + t_{r2}) + D_4(t_{f1} + t_m)}{2} \tag{3.9}$$

and the last term of (3.8), dependent on the base/constant load of the daily profile, is calculated using (3.10) as,

$$E_{Res2} = D_B\left(T - t_{r2} - t_m - t_{f1} - \frac{t_{r1} + t_{f2}}{2}\right). \tag{3.10}$$

This elementary approach from Section 3.2 can be used to model load profiles and estimate the daily load factor from first principles for the introduction of possible DR improvements.

3.3 PRACTICAL LOAD PROFILE MODELS FROM SITE READINGS

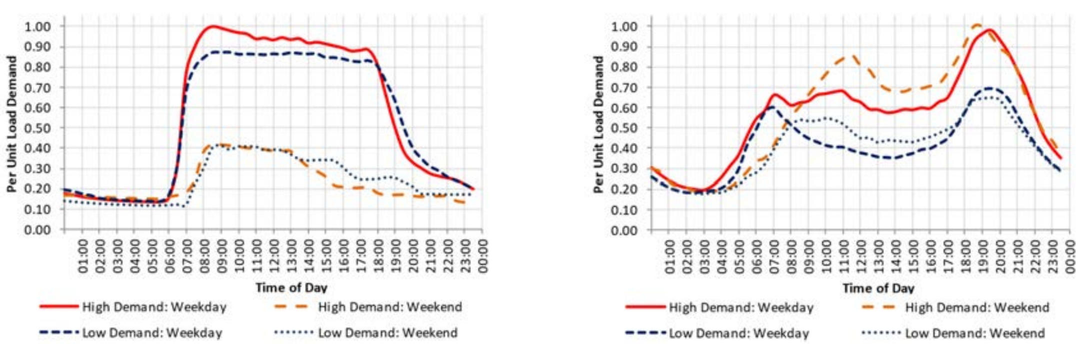
The most accurate approach for determining consumer load profiles is through measurement. Measured profiles will be used for representative system modelling and DR integration considering that accurate mathematical load profile estimations are extremely statistical, intermittent, and a continuously evolving field when considering the stochastic properties of real measured loads.

Measured load data for the selected case study development was unavailable at the time of writing as the development was still in the early engineering and planning phases. Therefore, existing and similar development metering data were selected for profile estimations, DR impact studies, and case study verification. Measured profile data will be used to verify previously published results, such as typical load profiles [81], BESS penetration and control [33], and PV penetration levels [22], [23], [96], and will serve as a baseline for case study simulations.

Similarities between the selected developments with metering data and the case study area are selected on the following comparable criteria:

- Similar development zoning (Example, Commercial, Residential, Industrial).
- Similar FAR/FSR and residential unit-per-hectare densities.
- Built by the same developer (Similar construction methods and standards).
- Built within the same municipal authority (Similar electrical specifications).
- Built within proximity to each other (Similar weather and climatic conditions).

The metering data available for the selected developments span over multiple years, providing an accurate daily and seasonal average. The processed (averaged and normalised) representative per unit data is shown in Figure 3.2 and are consistent with existing publications.



(a) (b)

Figure 3.2. Practical load profile readings to per unit yearly maximums.

(a) Commercial daily load profile. (b) Residential daily load profile.

High demand reading maximums are observed to be significantly lower than the estimated maximum demand calculations defined in the supply authority regulations and service agreements (kVA/unit per Section 2.5.1, or kVA/100 m^2 of GLA per Section 2.5.2), signifying that standards should be revised as discussed in Section 2.5.3. Both consumer type profiles show similar forms to the theoretical profiles and can be modelled likewise. Weekend residential profiles show the morning load shift to the afternoon as predicted in

Section 2.5.1 which is advantageous for PV generation profile matching. Normalised maximum demand peak comparisons are shown in Table 3.1.

Table 3.1 Normalised load profile yearly maximum demands comparison.

	Commercial		**Residential**	
	Weekday	**Weekend**	**Weekday**	**Weekend**
High Demand (Winter)	**100%**	42%	98%	**100%**
Low Demand (Summer)	87%	41%	69%	65%

The commercial load power factor can range from 0.80 to 0.98 lagging, and residential load power factor in the order of 0.90 to 0.99 lagging.

3.4 PROFILE CHANGES FROM INTEGRATED ENERGY STORAGE

BESSs are chosen as the basis for DR integration and load profile optimisation by reducing energy costs, reducing the maximum demand, and an improving load factor from more advanced power control capabilities provided over PV DG alternatives. External factors and weather do not influence BESS outputs the same as with PV DG, resulting in a more predictable and sustainable load profile modification through advanced power control options, albeit with the highest levelized energy costs. Various approaches to ultimately reduce system utilisation factors with BESS discharge for the benefit of both the end-user and utility are modelled in the following sections.

3.4.1 BESS rating factors

BESS ratings and operation are modelled within the two main components, namely ES_{PCS} as the nominal continuous active power rating of the PCS (limiting the maximum amount of energy that can be discharged/recharged from the system) and ES_{Cap} representing the total ES capacity. The power rating of the PCS (responsible for AC to AC, AC to DC, DC to DC, DC to AC round-trip conversion) will limit the maximum amount of energy that can be discharged or recharged from the system. By increasing the rated capacity of the

PCS unit, a higher magnitude of ES can be discharged assuming that the BESS components are still within the rated limits. Increasing the PCS (ES_{PCS}) and ES (ES_{Cap}) sub-components by the same percentage will have no impact on the overall system C-rate.

BESS rates of maximum recharge and discharge (C-rate or C-factor) are defined as the maximum amount of energy transferred in an hour of the rated capacity, limited by the manufacturing technology, battery chemistry/type, and module thermal design. This rating is specific to the anticipated application and operational requirements, with typical ES C-rate (ES_C) ranges for MWh-rated systems shown in (3.11) as,

$$0.2C < ES_C < 4.0C. \tag{3.11}$$

Low C-rate systems (0.2C to 1C) are rated for long duration low power discharge applications, such as load shifting, peak shaving, and renewable integration energy source balancing where the power demand occurs over longer timeframes. Medium (1C to 2C) to high (2C and higher) C-rate systems are rated for rapid response and high-power output applications that include short-duration backup power for grid stabilisation applications such as spinning reserve augmentation (awaiting backup generator start-up and grid synchronisation), fast frequency response/regulation, and voltage support. Increasing C-rates for higher discharge capability is more expensive, has the possibility of tripping the PCS unit (if incorrectly rated), and will exponentially lower the BESS efficiency and expected lifetime, with the system reaching end-of-life when ES capacity loss equals 20% [112].

Operating BESSs at low power for a longer time-period is more efficient compared to rapid cycling at high power, resulting in a design trade-off between convenience (fast charging/discharging) and system losses. Standby losses also occur in BESSs with chemical processes slowly but continuously releasing energy when not in use or by over-charging. Losses are dependent on the type of charging (constant current or constant voltage) and can be grouped as constant (heat produced by internal resistances) and variable (dependent on BESS operation) losses.

The efficiency ranges of Lithium-ion BESSs are estimated to the DC subcomponent (η_{DC}) using (3.12) and (3.13) as,

$$97.0\% \leq \eta_{DC\ Line\ \&\ Battery} \leq 98.0\% \tag{3.12}$$

$$96.0\% \leq \eta_{DC-DC\ Converter} \leq 96.6\% \tag{3.13}$$

and the PCS subcomponent (η_{PCS}) in (3.14) and (3.15) as,

$$96.0\% \leq \eta_{Inverter} \leq 98.0\% \tag{3.14}$$

$$96.0\% \leq \eta_{Transformer} \leq 99.0\%. \tag{3.15}$$

The conservative BESS round-trip efficiency, that also includes other operational losses ($\eta_{Operation}$), can be estimated to,

$$BESS_{\eta} = \eta_{DC} \cdot \eta_{PCS} \cdot \eta_{Operation} \approx 85\% \tag{3.16}$$

but should be re-evaluated per individual system, technology type, and OEM datasheets, with expected efficiencies ranging from 70% to 95% (Table 2.1).

For South African grid code "Power Gradient Constraint" (ramp rate) compliance, the maximum rate at which active power can be changed (either from BESS setpoints or other power changes) shall be possible to set to any value between 1% to 20% per minute of the nominal/maximum BESS power delivered (P_{nd}) or absorbed (P_{na}) [35]. A PRR limit can be conservatively selected from (3.17) and converted to (3.18) to control the BESS active power discharge/recharge ramp rates to,

$$ES_{PRR} \leq 4\%\ of\ ES_{PCS}\ per\ minute, \tag{3.17}$$

or matching 5-minute measurement data (t), equivalent to,

$$ES_{PRR} \leq 20\%\ of\ ES_{PCS}\ per\ 5\ minutes, \tag{3.18}$$

where ES_{PCS} is the maximum nominal active power of the BESS. The reduced rate (below grid code maximums) will limit BESS power changes to grid code compliance and therefore lower transient events in large system operations. The chosen limit is acceptable for all sections of BESS operational scenarios with the lower value also providing sufficient flexibility should intermittent PV support become unavailable at maximum generation requiring additional BESS discharge (Section 3.6.2).

BESS SoC maximums (fully rated charged) and minimums (fully rated discharged) are selected in (3.19) and (3.20) as,

$$SoC_{Max} = 90\%, \tag{3.19}$$

$$SoC_{Min} = 10\%, \tag{3.20}$$

of rated capacity for an 80% equivalent DoD (ES_{DoD}) rating (usable capacity from rated capacity, ES_{Cap}). Although DoD systems of up to 90% are possible (specifically for peak shaving applications), an 80% DoD is conservatively selected to include future capacity degradation and extend system lifetime [112] at a cost and footprint compromise. Other long term storage solutions, such as flow type batteries (Section 2.7.1), can have DoD ratings of up to 100% without impacting the system lifetime.

BESS operation will marginally increase the cumulative amount of grid energy required due to system losses as shown in (3.21),

$$ES_{Chrge} = \frac{ES_{Disch}}{BESS_{\eta}} = ES_{Disch} + ES_{Loss} \tag{3.21}$$

where ES_{Chrge} represents the total energy to be recharged, ES_{Disch} the total energy discharged to be recuperated, and ES_{Loss} the cycle energy losses within the BESS.

Excluding ramp-up and ramp-down, energy storage is recharged in evenly divided energy magnitudes within the defined recharge period t_{ch}. Maximising the recharge period within the evening to morning off-peak tariff period contributes to optimal cost savings, improved load factors, reduced fast charging losses, and decreased recharge demands. A 30-minute BESS inactive state between cycles is required to minimise system strains. The maximum load profile t_{ch} period demand increase following BESS recharge, also representing the PCS power rating requirement in the t_{ch} period, can be calculated using (3.22),

$$ES_{PCS,Chrge} = \frac{ES_{Chrge}}{(N_{ch} + 1 - \frac{1}{ES_{PRR}})} \tag{3.22}$$

where N_{ch} is the number of t recharge slots within the t_{ch} period. The BESS recharge power ramp rate percentage (ES_{CRR}) to the PCS rating (ES_{PCS}) per measuring period t, can be calculated using (3.23) as,

$$ES_{CRR} = \frac{ES_{PCS,Chrge} \cdot ES_{PRR}}{ES_{PCS}} \times 100\% \leq ES_{PRR} \times 100\% \tag{3.23}$$

where ES_{PRR} is the selected PCS ramp rate limit. Recharge ES_{CRR} will be equal to or lower than the discharge ES_{PRR} considering the power limitation set by the PCS rating. ES_{CRR} values approaching ES_{PRR} indicate a higher PCS utilisation factor in the recharge state.

Two control schemes are proposed:

- Load Following (Load%): BESS taking over a specified percentage of the load (Section 2.7, Section 3.4.2, Section 3.4.3).
- Peak Shaving (Clip%): BESS limiting the load maximums to a predetermined value (Section 3.4.4).

For the load following approach, the defined load to be transferred to BESS discharge is defined in (3.24) such that,

$$D_L = K \cdot MD_{Load} \cdot PF_{Load}. \tag{3.24}$$

For the peak shaving approach, the demand setpoint D_C (Clipped Demand) is defined in (3.25) such that,

$$D_C = (1 - K) \cdot MD_{Load} \cdot \frac{PF_{Load}}{PF_{DR}}. \tag{3.25}$$

K is the percentage of the load active power component of the maximum demand (MD_{Load}) to be transferred to the BESS (load following approach) or shaved (peak shaving approach), representing the ES penetration percentage (ES_{Pen}). PF_{Load} and regulated PF_{DR} are the power factors of the original load and the DR integrated load (for grid code compliance) respectively. The BESS power rating for discharge operation, $ES_{PCS,Disch}$, is defined in (3.26) for load following as,

$$ES_{PCS,Disch} = D_L \tag{3.26}$$

or in (3.27) for peak shaving as,

$$ES_{PCS,Disch} = MD_{Load} \cdot PF_{Load} - D_C \cdot PF_{DR} = MD_{Load} \cdot PF_{Load} \cdot K. \tag{3.27}$$

Combining the PCS power requirements from (3.22) and (3.26) or (3.27), the minimum PCS power rating, $ES_{PCS,Min}$, is defined where,

$$ES_{PCS,Min} = max\left(ES_{PCS,Chrge} \, , \, ES_{PCS,Disch}\right). \tag{3.28}$$

Resizing $ES_{PCS,Min}$ to include a practical C-rate for the final BESS ES_{PCS} rating is calculated in (3.29) where,

$$ES_{PCS} = max(ES_{PCS,Min} \, , \, ES_C \cdot ES_{Cap}). \tag{3.29}$$

To evaluate the different approaches to BESS integration, the following variables are defined in Table 3.2 as a per unit function of MD_{Load}.

Table 3.2 BESS evaluation variables.

Variable	Unit	Description
MD_{Load}	kVA	Original load yearly Maximum/Peak Demand at the POC.
ES_{Pen}	%	Load%: Percentage of load transferred to the BESS (K). Clip%: Percentage of peak demand shaved by the BESS (K).
MD_{DR}	kVA/MD_{Load}	Revised Maximum Demand at the POC.
MD_T	hh:mm	Time of adjusted daily Maximum Demand.
LF	%	Load Factor.
ES_{PCS}	kW/MD_{Load}	Minimum BESS PCS power rating per (3.28).
ES_{Cap}	kWh/MD_{Load}	BESS capacity rating (includes DoD from SoC_{Max} & SoC_{Min}).
ES_{CRR}	%	BESS charge 5-minute ramp rates.
ES_C	pu	Maximum BESS C-rate.

Based on the evaluation criteria above, three BESS control schemes are analysed in Section 3.4.2 to Section 3.4.4 with BESSs supporting a specified value of connected loads during the selected discharge periods. Loads are assumed to have unity power factor for active power control scheme evaluations.

3.4.2 BESS application: Energy Security (Standby)

Focusing on continued operation and energy security, BESSs can be rated to serve as a source of backup supply. With the ongoing advancement in BESS technologies, as well as a continued reduction of costs observed, BESSs are anticipated to become a competitive backup supply option with a levelized energy cost similar to or lower than that of diesel generator alternatives while also offering a cleaner and more sustainable solution.

A high demand supply downtime of 4-hours is selected as a worst-case scenario for determining the BESS rating. This includes the maximum load peak from 08:00 to 12:00 for commercial (weekday), and 17:00 to 21:00 for residential (weekend), but will be site and requirement specific. Energy management becomes crucial during supply downtime should the BESS be rated to only provide backup for pre-selected critical loads. BESS recharge times are selected within the off-peak evening to morning period.

Commercial BESS ratings (per unit of original load maximum demand) are shown in Table 3.3 with varying levels of load transfer in the rated 4-hour downtime period.

Table 3.3 Commercial high demand weekday BESS energy backup ratings.

ES_{Pen}	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
ES_{PCS}	n/a	0.10	0.20	0.30	0.40	0.50	0.60	0.70	0.80	0.90	1.00
ES_{Cap}	n/a	0.45	0.89	1.34	1.78	2.23	2.68	3.12	3.57	4.01	4.46
ES_{CRR}	n/a	11.12%	11.12%	11.12%	11.12%	11.12%	11.12%	11.12%	11.12%	11.12%	11.12%
ES_C	n/a	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22

Residential BESS ratings (per unit of original load maximum demand) are shown in Table 3.4 with varying levels of load transfer in the rated 4-hour downtime period.

Table 3.4 Residential high demand weekend BESS energy backup ratings.

ES_{Pen}	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
ES_{PCS}	n/a	0.10	0.20	0.30	0.40	0.50	0.60	0.70	0.80	0.90	1.00
ES_{Cap}	n/a	0.43	0.85	1.28	1.71	2.14	2.56	2.99	3.42	3.84	4.27
ES_{CRR}	n/a	12.06%	12.06%	12.06%	12.06%	12.06%	12.06%	12.06%	12.06%	12.06%	12.06%
ES_C	n/a	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23

The defined *CF*, as a system cost evaluation tool, cannot be included in this mode of operation as it does not consider the main purpose of this approach, which is the prevention of non-operational revenue loss. As residential downtime does not have a direct impact on the revenue stream (as with commercial consumers), energy storage backup systems are used primarily as a new development selling attraction and resident convenience.

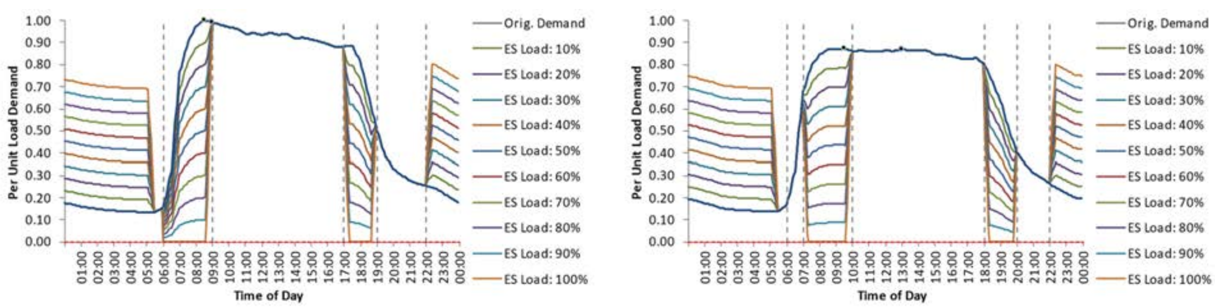
Transferring critical loads from the utility to the BESS during grid-supply downtime will not have an impact on the utility equipment/utilisation ratings as BESS control should isolate the system from the network (islanding protection). However, internal load maximums should be evaluated to confirm internal equipment rating compliance with BESS discharge levels. The resulting demand increase from BESS recharge in the off-peak period must be evaluated to ensure that the POC does not trip on recharge overload.

Backup operation can be included as a secondary selectable function from BESS control should the NSP load shedding schedules be known in addition to other BESS applications (from the following sections) if surplus capacity is available.

3.4.3 BESS application: Energy Arbitrage

The most effective approach to BESS energy arbitrage is to discharge during weekday peak tariff periods. Off-peak recharge times are selected from 22:00 to 06:00 for commercial and 23:00 to 05:30 for residential to ensure a minimum 30-minute BESS inactive period between states.

Figure 3.3 illustrates the altered weekday commercial demand profiles at the POC implementing Energy Arbitrage during the two peak tariff discharge periods, with various levels of BESS load transfer.



(a) (b)

Figure 3.3. Commercial weekday with levels of BESS energy arbitrage.

(a) High demand. (b) Low demand.

Commercial results per unit of the original load maximum demand are shown in Table 3.5 (high demand) and Table 3.6 (low demand).

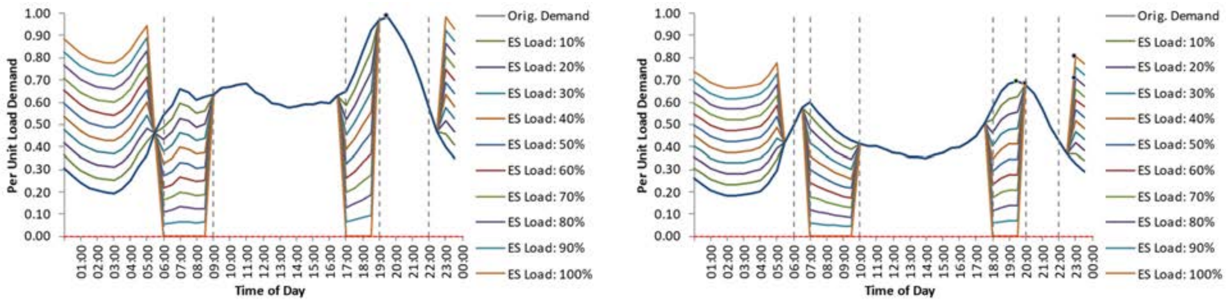
Table 3.5 Commercial high demand weekday BESS energy arbitrage results.

ES_{Pen}	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MD_{DR}	1.00	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
MD_T	08:30	09:00	09:00	09:00	09:00	09:00	09:00	09:00	09:00	09:00	09:00
LF	56.41%	57.09%	57.34%	57.59%	57.84%	58.09%	58.35%	58.60%	58.85%	59.10%	59.35%
ES_{PCS}	n/a	0.10	0.20	0.30	0.40	0.50	0.60	0.70	0.80	0.90	1.00
ES_{Cap}	n/a	0.42	0.85	1.27	1.69	2.12	2.54	2.96	3.39	3.81	4.23
ES_{CRR}	n/a	11.12%	11.12%	11.12%	11.12%	11.12%	11.12%	11.12%	11.12%	11.12%	11.12%
ES_C	n/a	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24

Table 3.6 Commercial low demand weekday BESS energy arbitrage results.

ES_{Pen}	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MD_{DR}	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
MD_T	09:30	13:00	13:00	13:00	13:00	13:00	13:00	13:00	13:00	13:00	13:00
LF	61.83%	62.31%	62.60%	62.88%	63.17%	63.45%	63.74%	64.02%	64.31%	64.60%	64.88%
ES_{PCS}	n/a	0.09	0.17	0.26	0.35	0.44	0.52	0.61	0.70	0.78	0.87
ES_{Cap}	n/a	0.42	0.84	1.27	1.69	2.11	2.53	2.95	3.38	3.80	4.22
ES_{CRR}	n/a	12.72%	12.72%	12.72%	12.72%	12.72%	12.72%	12.72%	12.72%	12.72%	12.72%
ES_C	n/a	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21

Figure 3.4 illustrates the altered weekday residential demand profiles at the POC implementing Energy Arbitrage during the two peak tariff discharge periods, with various levels of BESS load transfer.



(a) (b)

Figure 3.4. Residential weekday with levels of BESS energy arbitrage.

(a) High demand. (b) Low demand.

Residential results per unit of the original load maximum demand are shown in Table 3.7 (high demand) and Table 3.8 (low demand).

Table 3.7 Residential high demand weekday BESS energy arbitrage results.

ES_{Pen}	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MD_{DR}	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
MD_T	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30
LF	57.17%	57.40%	57.63%	57.86%	58.09%	58.32%	58.55%	58.78%	59.01%	59.24%	59.47%
ES_{PCS}	n/a	0.10	0.19	0.29	0.38	0.48	0.58	0.67	0.77	0.86	0.96
ES_{Cap}	n/a	0.38	0.77	1.15	1.54	1.92	2.31	2.69	3.08	3.46	3.84
ES_{CRR}	n/a	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
ES_C	n/a	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25

Table 3.8 Residential low demand weekday BESS energy arbitrage results.

ES_{Pen}	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MD_{DR}	0.69	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.69	0.73	0.78
MD_T	19:30	20:00	20:00	20:00	20:00	20:00	20:00	20:00	22:50	22:50	22:50
LF	58.91%	60.19%	60.46%	60.73%	61.00%	61.27%	61.54%	61.80%	61.34%	57.92%	54.88%
ES_{PCS}	n/a	0.07	0.14	0.21	0.28	0.35	0.42	0.48	0.55	0.62	0.69
ES_{Cap}	n/a	0.31	0.62	0.93	1.24	1.55	1.86	2.17	2.48	2.79	3.11
ES_{CRR}	n/a	12.67%	12.67%	12.67%	12.67%	12.67%	12.67%	12.67%	12.67%	12.67%	12.67%
ES_C	n/a	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22

A reduced commercial and residential maximum demand can be seen if the original peak occurs during the peak tariff periods.

Commercial and residential consumers will show a reducing CF (energy cost savings) per increasing BESS load transfer percentage provided that the sum of $LCUS_{ES}$ (discharge costs) and $T_{Off\text{-}Peak}$ energy (recharge costs) are cheaper compared to the T_{Peak} energy costs, presenting an energy arbitrage saving for a reduced BESS payback period. With BESSs (especially the battery component) becoming significantly cheaper with longer lifetimes, higher NSP energy cost inflation rates expected, and the possibility of a lowered $LCUS_{ES}$ from PPAs and other financing options, the breakeven year for energy arbitrage can be further reduced through cumulative yearly savings within the operational lifetime of the BESS.

High penetration BESS integrated off-peak recharge demands that exceed the original load maximums will worsen CF estimations due to higher demand charges outweighing smaller energy arbitrage cost savings. This will also lead to a worsening load factor and an increased risk of overload tripping at the main connection, highlighting the importance of selecting and confirming recharge times and BESS operational levels through time-based profile simulations.

The focus on reducing energy costs and achieving shorter BESS payback periods will render this approach feasible for both commercial and residential consumers, particularly during high demand seasons with high peak tariff energy costs. However, it is essential to consider both high and low seasonal demand estimations when determining the optimal BESS rating to align with financial expectations.

The installation of PV DG will offer additional energy support during midday hours which are not defined for energy arbitrage and will further enhance the benefits of this approach through a lower LCOE. Peak tariff energy arbitrage is not viable for weekend profiles (as there are no peak tariff energy charges) and will not lower distribution (external network) equipment ratings, irrespective of penetration level.

3.4.4 BESS application: Peak shaving (Demand reduction emphasis)

The operational fundamentals of BESSs developed in Section 3.4.3 allows the BESS to discharge only during pre-set peak tariff periods to take over a specified percentage of the demand in a load following approach. This results in demand reductions not necessarily contributing to load maximums and thereby worsening the POC load factor.

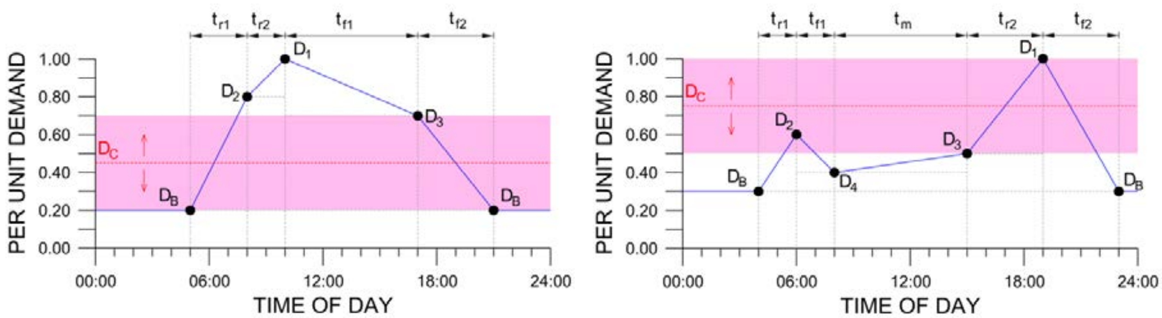
In contrast, a peak shaving approach offers several advantages over the load following approach by specifically focusing on maximum demand reduction (and consequently, utilisation factors) with less BESS discharge required for a load factor improvement. This is achieved by configuring the BESS to discharge when the load demand exceeds a specified maximum demand value to effectively reducing the POC active demand to a constant (levelled) maximum. The total discharged energy and losses are recuperated within the off-peak evening period.

Defining the maximum discharge limit:

An optimal load factor is dependent on the altered maximum demand (MD_{DR}), the amount of energy shaved/clipped from the profile, the time of allowable recharge, and the increased off-peak demand from BESS recharge. A limit exists where the rising t_{ch}

demands could surpass the new altered/shaved D_C demand of (3.25), conversely increasing the system maximum demand, utilisation factor, supply authority costs, and worsening the load factor, resulting in oversized/unused BESS capacities and risking protection trips.

To determine the maximum amount of demand that can be shaved from profiles for the best load factor, the D_C limit ranges are conceptually illustrated in Figure 3.5 (as a variant of Figure 3.1).



(a) (b)

Figure 3.5. Load model estimation points and maximum D_C magnitude range.

(a) Commercial daily load profile. (b) Residential daily load profile.

Figure 3.5a and (3.30) show the limits of the commercial profile D_C setpoint such that the D_C magnitude must be,

$$D_B < D_C < D_3 \tag{3.30}$$

since the original base load will always remain the lowest demand. The commercial energy shaved ($E_{C,Com}$) can be calculated as a function of the changing D_C demand with the condition of (3.30) and the load model of Figure 3.5a. This is shown in (3.31) as,

$$E_{C,Com} = E_{C,Con} + E_{C,Var} = ES_{Disch} \tag{3.31}$$

where $E_{C,Con}$ represents the constant energy shaved from the peak due to the condition set in (3.30). This is calculated in (3.32) as,

$$E_{C,Con} = \frac{t_{f1}(D_1 - D_f) + t_{r2}(D_1 - D_r)}{2}. \tag{3.32}$$

The variable energy shaved ($E_{C,Var}$) is calculated in (3.33) as,

$$E_{C,Var} = t_{r2}(D_r - D_C) + t_{f1}(D_f - D_C) + \frac{t_{r1}(D_r - D_C)^2}{2(D_r - D_B)} + \frac{t_{f2}(D_f - D_C)^2}{2(D_f - D_B)} \tag{3.33}$$

to the changing D_C magnitude.

For residential profiles it is assumed that both morning and evening peaks are included (but excluding the midday demand) to model the maximum amount of energy that can be shaved. This range is shown in Figure 3.5b and the condition set in (3.34) as,

$$D_3 < D_C < D_1. \tag{3.34}$$

The residential energy shaved ($E_{C,Res}$) can be calculated from Figure 3.5b and (3.35) as a function of the changing D_C demand with the condition of (3.34) as,

$$E_{C,Res} = E_{C,pk1} + E_{C,pk2} = ES_{Disch} \tag{3.35}$$

where $E_{C,pk1}$ is the energy shaved from the morning peak if the shaved magnitude complies with the condition defined in (3.34) and (3.36) such that,

$$D_3 < D_C < D_2 \tag{3.36}$$

and can then be calculated in (3.37) as,

$$E_{C,pk1} = \frac{t_{r1}(D_2 - D_C)^2}{2(D_2 - D_B)} + \frac{t_{f1}(D_2 - D_C)^2}{2(D_2 - D_4)}. \tag{3.37}$$

If the shaved demand exceeds the morning peak as shown in (3.38) so that,

$$D_2 < D_C < D_1 \tag{3.38}$$

the morning peak is not shaved, and the $E_{C,pk1}$ term changes to zero. Equation (3.39) determines the $E_{C,pk2}$ term (energy shaved from the afternoon peak) as,

$$E_{C,pk2} = \frac{t_{r2}(D_1 - D_C)^2}{2(D_1 - D_3)} + \frac{t_{f2}(D_1 - D_C)^2}{2(D_1 - D_B)}. \tag{3.39}$$

Equation (3.31) for commercial and (3.35) for residential estimates the amount of daily energy discharged by the BESS (ES_{Disch}) that must be recuperated with losses (ES_{Loss}) within the defined off-peak tariffing recharge period (t_{ch}).

The increase of recharge period demands is directly dependent on the energy discharged and related BESS losses. These can be lowered with the installation of PV DG to pre-emptively reduce the demands defined within the defined BESS shaving periods (especially within commercial profiles), reducing BESS strain/losses, limiting power flow locally, and lowering the recharge period load demands (Section 3.6).

The maximum amount of BESS peak shaving is achieved when the load factor is at its highest and the maximum off-peak recharge-increasing demand (D_R) approaches but never exceeds the new shaved load maximum demand (MD_{DR}) as per Figure 3.6 and the (3.40) condition where,

$$MD_{DR} = D_C \geq D_R. \tag{3.40}$$

Theoretical altered BESS enabled load profiles adhering to the defined discharge/recharge times and the optimal load factor constraints of (3.40) are conceptually illustrated in Figure 3.6. Small demand dips will still worsen load factors (between D_R and D_C times) since BESS recharge times are fixed and pre-set within BESS controls to determine the equivalent amount of energy to be recharged by the system over the selected t_{ch} period.

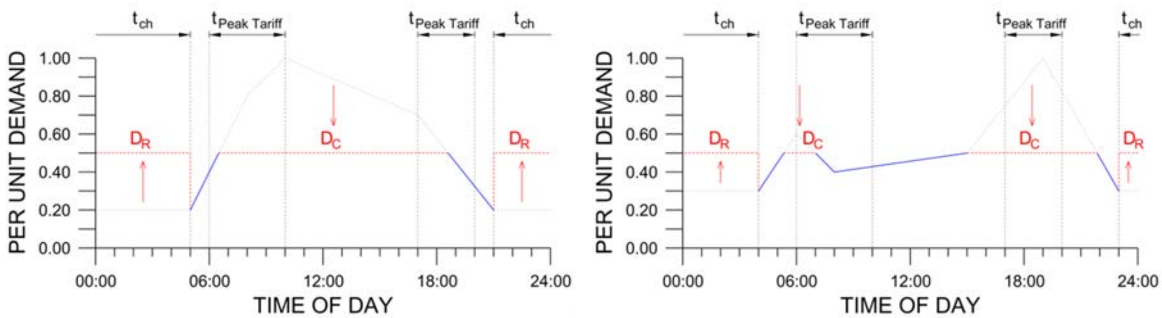


Figure 3.6. Conceptual load profiles with maximum BESS peak shaving integration.

(a) Altered commercial load profile. (b) Altered residential load profile.

A scenario exists within residential profiles where, with the inclusion of the morning peak as per (3.37), the resulting new off-peak demand ($D_{R,n}$) will exceed the new shaved demand setpoint (D_C). To reduce the amount of energy to be recharged, demand shaving from the morning peak must be excluded and the condition of (3.34) revised to (3.38), with the morning peak not contributing to the total BESS discharged energy.

This section provides a simplified first principle approach as a basic estimation tool to highlight key concepts and limits for BESS peak shaving operation but could be adapted to incorporate other discharge models. It is shown that the maximum amount of BESS peak shaving is achieved when the load factor is at its highest, and the increased off-peak demand (from BESS recharge) does not exceed the newly altered shaved maximums. However, achieving the maximum load factor (and the associated benefits thereof) from BESS operation does not necessarily imply a valid practical and economical approach considering the high costs associated with BESS installation and operation and must be considered in feasibility studies.

Considering the main operations and limitations mentioned above, software can be developed to analyse exact load profiles more accurately for the calculation of maximum BESS discharge, DR equipment ratings, additional practical constraints/limits, and enforcing integration control for the enhancement of BESS and PV DG synergism. See

Section 3.6 and Addendum A for the full developed control system and Chapter 4 for case study comparisons.

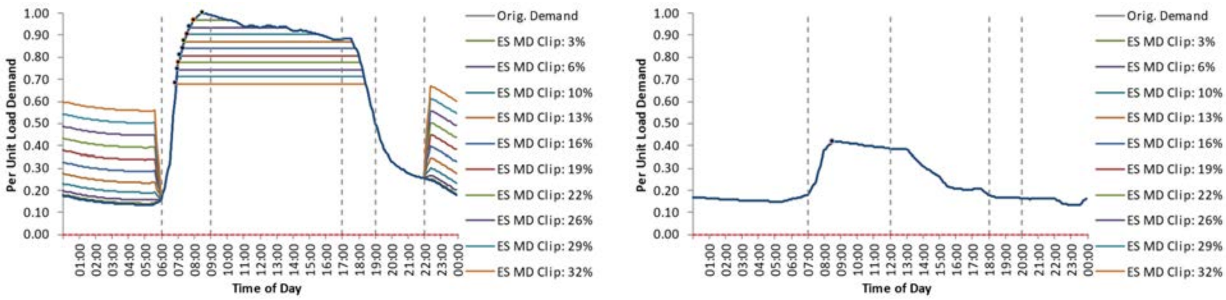
Commercial loads (BESS peak shaving):

For commercial peak shaving, both high and low demand weekday profiles should be considered for preliminary BESS sizing. Table 3.9 estimates the highest achievable BESS peak shaving possible with a unity power factor and $BESS_{\eta}$, ES_{PRR}, and ES_{DoD} as previously defined. Recharge times are maximised to decrease BESS recharge demands. The pre-rated annual system ratings and operational settings are optimised/revised within the limitation of (3.40).

Table 3.9 Preliminary per unit commercial BESS peak shaving rating selection.

	Unit	High Demand Weekday	Low Demand Weekday Initial	Low Demand Weekday Revised
ES_{Pen}	%	**32%**	37%	**32%**
MD_{DR}	kVA/MD_{Load}	**0.68**	0.63	**0.68**
LF	%	85.94	88.46	81.31
$ES_{PCS,Min}$	kW/MD_{Load}	**0.42**	0.38	**0.42** (0.29)
ES_{Cap}	kWh/MD_{Load}	**3.44**	3.11	**3.44** (2.36)
ES_{CRR}	%	20%	20%	14%
Discharge	hh:mm	06:00 – 22:00	06:00 – 22:00	06:00 – 22:00
Recharge	hh:mm	22:00 – 06:00	22:00 – 06:00	22:00 – 06:00

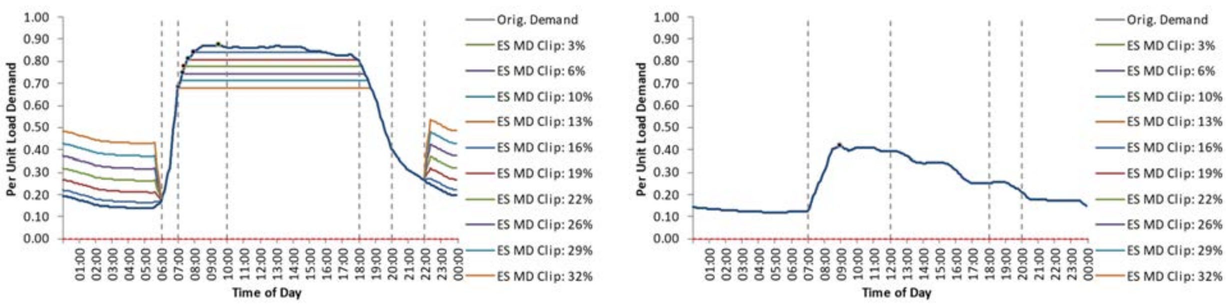
Figure 3.7 and Figure 3.8 illustrate the altered commercial load profiles at the POC with increasing levels of BESS peak shaving during the discharge enabled period. All profile maximums are kept within shaving setpoints by BESS operation. Weekend profiles, with load maximums well below the possible peak shaving demand setpoint, do not require BESS discharge.



(a) (b)

Figure 3.7. Commercial high demand with BESS peak shaving levels.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 3.8. Commercial low demand with BESS peak shaving levels.

(a) Weekday demand. (b) Weekend demand.

Weekday commercial minimum ratings and results per unit of the original load maximum demand are shown in Table 3.10 (high demand) and Table 3.11 (low demand).

Table 3.10 Commercial high demand weekday BESS peak shaving results.

ES_{Pen}	**0%**	**3%**	**6%**	**10%**	**13%**	**16%**	**19%**	**22%**	**26%**	**29%**	**32%**
MD_{DR}	1.00	0.97	0.94	0.90	0.87	0.84	0.81	0.78	0.74	0.71	0.68
MD_{T}	08:30	08:00	07:45	07:35	07:25	07:20	07:10	07:05	07:00	07:00	06:55
LF	56.41%	58.30%	60.37%	62.69%	65.23%	68.01%	71.01%	74.28%	77.82%	81.70%	85.94%
ES_{PCS}	n/a	0.03	0.06	0.10	0.13	0.16	0.20	0.26	0.31	0.37	**0.42**
ES_{Cap}	n/a	0.05	0.17	0.45	0.81	1.22	1.65	2.09	2.53	2.99	**3.44**
ES_{CRR}	n/a	3.51%	6.59%	11.38%	15.47%	18.73%	20.00%	20.00%	20.00%	20.00%	20.00%
ES_{C}	n/a	0.70	0.37	0.22	0.16	0.13	0.12	0.12	0.12	0.12	0.12

Table 3.11 Commercial low demand weekday BESS peak shaving results.

ES_{Pen}	**0%**	**3%**	**6%**	**10%**	**13%**	**16%**	**19%**	**22%**	**26%**	**29%**	**32%**
MD_{DR}	0.87	0.87				0.84	0.81	0.78	0.74	0.71	0.68
MD_{T}	09:30	09:30				08:00	07:40	07:25	07:20	07:10	07:05
LF	61.83%	61.83%				64.32%	67.14%	70.23%	73.60%	77.28%	81.31%
ES_{PCS}	n/a	0.00				0.03	0.07	0.12	0.18	0.23	0.29
ES_{Cap}	n/a	0.00				0.21	0.59	1.01	1.45	1.90	2.36
ES_{CRR}	n/a	n/a				16.64%	20.00%	20.00%	20.00%	20.00%	20.00%
ES_{C}	n/a	n/a				0.15	0.12	0.12	0.12	0.12	0.12

The highest yearly consistent maximum demand reduction in commercial loads (with an improving the load factor) can be seen with up to 32% of maximum demand peak shaving, as limited by the high demand weekday profile (Table 3.9). When increasing over 32% peak shaving, the recharge demand will surpass the altered/shaved load maximum, increasing the system maximum demand (and costs), result in oversized/unused BESS capacities, and risk tripping the POC breaker on overload. Weekend peaks are well below the defined 68% of MD_{Load} per unit shaving setpoint, and no peak shaving discharge is required from the BESS. Maximum discharge commercial BESS ratings with discharge/recharge periods are defined in Table 3.9 with the minimum PCS and ES components initially rated to 0.42 kW/MD_{Load} and 3.44 kWh/MD_{Load} respectively.

An improvement in the commercial load factor can be realised from 56% to 86% (high demand weekday) and 62% to 81% (low demand weekday). Commercial low demand weekday profiles do not require peak shaving up to 12% ES_{Pen} since the weekday load maximum demand is already lower than the variable BESS shaving setpoint. High levels of energy discharge required in short periods of time will result in a higher system C-rate requirement. This is more prominent in smaller capacity rated peak shaving systems (if recommended from practical feasibility studies) and must be considered in the proposed system ratings. A higher ES component (defined in Table 3.9 for maximum commercial system ratings) will reduce the C-rate requirement to a more practical value (Section 3.6.2).

Due to weekday commercial loads largely falling within midday hours, any high penetration weekday peak shaving operation will require increasing levels of BESS capacity to discharge during standard tariff periods. This will worsen the *CF* from expensive BESS discharge and recharge costs over minimal demand savings, even-though load factor improvements are realised. This turning point for maximum discharge from a cost perspective for lower rated BESSs can be calculated and visualised by plotting the *CF* over the full ES_{Pen} range. A *CF* dip (typically within low ES_{Pen} ranges) will be observed where energy costs start exceeding the demand savings.

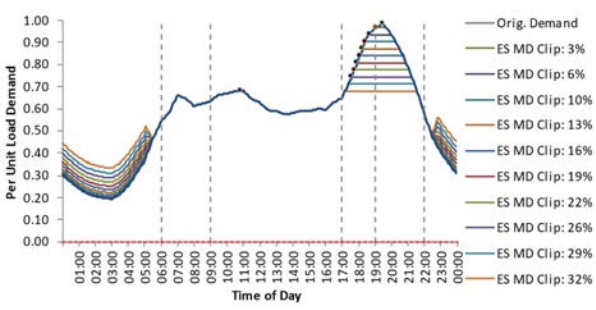
Residential loads (BESS peak shaving):

For residential peak shaving, high demand profiles should be considered for preliminary BESS sizing. Table 3.12 estimates the highest achievable BESS peak shaving possible with a unity power factor and $BESS_{\eta}$, ES_{PRR}, and ES_{DoD} as previously defined. Recharge times are maximised to decrease BESS recharge demands. The pre-rated annual system ratings and operational settings are optimised/revised within the limitation of (3.40).

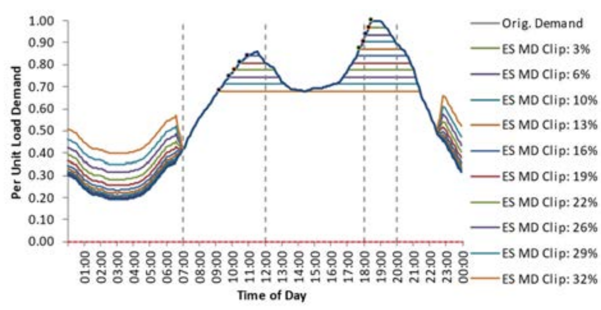
Table 3.12 Preliminary per unit residential BESS peak shaving rating selection.

	Unit	High Demand Weekday Initial	High Demand Weekend	High Demand Weekday Revised
ES_{Pen}	%	37%	32%	**32%**
MD_{DR}	kVA/MD_{Load}	0.63	0.68	**0.68**
LF	%	90.59	87.05	83.56
$ES_{PCS,Min}$	kW/MD_{Load}	0.35	0.32	**0.32** (0.30)
ES_{Cap}	kWh/MD_{Load}	1.42	1.79	**1.79** (0.99)
ES_{CRR}	%	11%	13%	9%
Discharge	hh:mm	06:00 – 22:00	07:00 – 22:00	06:00 – 22:00
Recharge	hh:mm	22:30 – 05:30	22:30 – 07:00	22:30 – 05:30

Figure 3.9 and Figure 3.10 illustrate the altered residential load profiles at the POC with increasing levels of BESS peak shaving during the discharge enabled period. All profile maximums are kept within shaving setpoints by BESS operation. Low demand weekday profiles, with load maximums already marginal to the peak shaving demand setpoint, require lower levels of BESS peak shaving discharge. Low demand weekend profiles, with load maximums below the possible peak shaving demand setpoint, do not require BESS discharge.



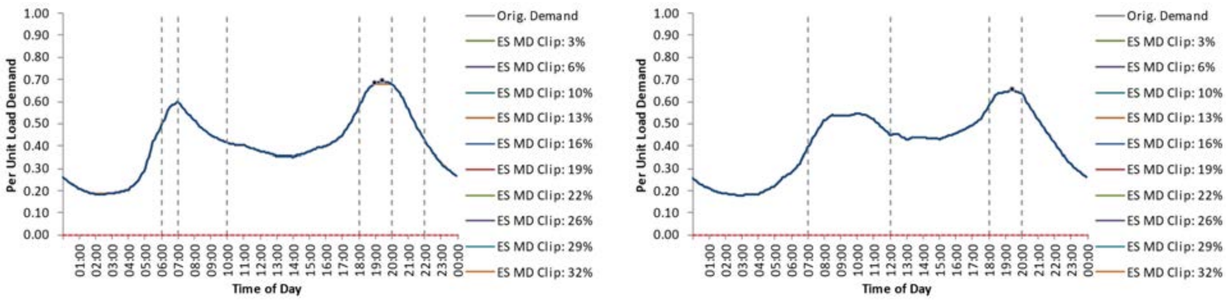
(a)



(b)

Figure 3.9. Residential high demand with BESS peak shaving levels.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 3.10. Residential low demand with BESS peak shaving levels.

(a) Weekday demand. (b) Weekend demand.

Residential minimum ratings and results per unit of the original load maximum demand are shown in Table 3.13 (high demand, weekday), Table 3.14 (high demand, weekend), and Table 3.15 (low demand, weekday). C-rates over 1C are highlighted.

Table 3.13 Residential high demand weekday BESS peak shaving results.

ES_{Pen}	0%	3%	6%	10%	13%	16%	19%	22%	26%	29%	32%
MD_{DR}	0.98	0.97	0.94	0.90	0.87	0.84	0.81	0.78	0.74	0.71	0.68
MD_T	19:30	19:05	18:40	18:25	18:15	18:05	17:55	17:45	17:35	17:25	10:50
LF	57.17%	58.10%	60.11%	62.28%	64.62%	67.15%	69.89%	72.87%	76.12%	79.66%	83.56%
ES_{PCS}	n/a	0.02	0.05	0.08	0.11	0.14	0.18	0.21	0.24	0.27	0.30
ES_{Cap}	n/a	0.01	0.05	0.11	0.19	0.29	0.40	0.53	0.67	0.82	0.99
ES_{CRR}	n/a	1.11%	2.75%	3.96%	4.91%	5.73%	6.47%	7.19%	7.87%	8.54%	9.20%
ES_C	n/a	**2.53**	**1.03**	0.71	0.58	0.49	0.44	0.39	0.36	0.33	0.31

Table 3.14 Residential high demand weekend BESS peak shaving results.

ES_{Pen}	**0%**	**3%**	**6%**	**10%**	**13%**	**16%**	**19%**	**22%**	**26%**	**29%**	**32%**
MD_{DR}	1.00	0.97	0.94	0.90	0.87	0.84	0.81	0.78	0.74	0.71	0.68
MD_T	18:30	18:20	18:10	18:00	17:45	11:00	10:30	10:10	09:50	09:30	09:15
LF	58.14%	60.08%	62.17%	64.41%	66.84%	69.47%	72.35%	75.51%	78.98%	82.80%	87.05%
ES_{PCS}	n/a	0.03	0.06	0.10	0.13	0.16	0.19	0.22	0.26	0.29	**0.32**
ES_{Cap}	n/a	0.03	0.08	0.15	0.24	0.37	0.55	0.78	1.06	1.38	**1.79**
ES_{CRR}	n/a	2.22%	2.99%	3.68%	4.39%	5.31%	6.56%	8.02%	9.52%	11.03%	12.87%
ES_C	n/a	**1.04**	0.77	0.63	0.53	0.43	0.35	0.29	0.24	0.21	0.18

Table 3.15 Residential low demand weekday BESS peak shaving results.

<table>
<tr><th>ES_{Pen}</th><th>0%</th><th>3%</th><th>6%</th><th>10%</th><th>13%</th><th>16%</th><th>19%</th><th>22%</th><th>26%</th><th>29%</th><th>32%</th></tr>
<tr><td>MD_{DR}</td><td>0.69</td><td colspan="9">0.69</td><td>0.68</td></tr>
<tr><td>MD_T</td><td>19:30</td><td colspan="9">19:30</td><td>19:00</td></tr>
<tr><td>LF</td><td>58.91%</td><td colspan="9">58.91%</td><td>59.98%</td></tr>
<tr><td>ES_{PCS}</td><td>n/a</td><td colspan="9">0.00</td><td>0.01</td></tr>
<tr><td>ES_{Cap}</td><td>n/a</td><td colspan="9">0.00</td><td>0.01</td></tr>
<tr><td>ES_{CRR}</td><td>n/a</td><td colspan="9">n/a</td><td>2.24%</td></tr>
<tr><td>ES_C</td><td>n/a</td><td colspan="9">n/a</td><td>1.26</td></tr>
</table>

The highest yearly consistent maximum demand reduction in residential loads (with an improving the load factor) can be seen with up to 32% of maximum demand peak shaving, as limited by the high demand weekend profile (Table 3.12). When increasing over 32% peak shaving, the recharge demand will surpass the altered/shaved load maximum, increasing the system maximum demand (and costs), result in oversized/unused BESS capacities, and risk tripping the POC breaker on overload. Low demand peaks are already close to the defined 68% of MD_{Load} per unit shaving setpoint, resulting in marginal to zero discharge required from the BESS. Maximum discharge residential BESS ratings with discharge/recharge periods are defined in Table 3.12 with the minimum PCS and ES components initially rated to 0.32 kW/MD_{Load} and 1.79 kWh/MD_{Load} respectively.

An improvement of the residential load factor can be realised from 57% to 84% (high demand weekday), 58% to 87% (high demand weekend), and 59% to 60% (low demand weekday). Residential low demand weekday profiles do not require peak shaving discharge up to 30% ES_{Pen} since the maximum load demand is already marginal to the variable peak shaving setpoint resulting in low LF improvements. High levels of energy discharge required in short periods of time will result in a higher system C-rate requirement. This is more prominent in smaller capacity rated peak shaving systems (if recommended from practical feasibility studies) and must be considered in the proposed system ratings. Marginal peak shaving is required in low demand weekday profiles (indicated by the low values of ES_{Cap} required in Table 3.15) and will result in unused capacity surplus from high demand profile ratings. These surplus capacities can be utilised more effectively in other additional low demand operational modes such as weekday peak tariff energy arbitrage or standby applications. A higher ES component (defined in Table 3.12 for maximum residential system ratings) will reduce the C-rate requirement to a more practical value (Section 3.6.2).

A significant amount of weekday peak shaving will coincide with peak tariff demands (especially in the late afternoon) and will contribute to an improving load factor and CF by taking advantage of a decreasing maximum demand and high tariff energy arbitrage cost savings. However, high demand weekend residential loads require significant peak shaving during low and standard tariffing periods that will result in a worsening CF from expensive BESS discharge and recharge costs over minimal demand savings, even-though load factor improvements are realised. High demand weekend profiles will therefore not contribute to yearly cost savings but will be offset by the potential savings achievable in weekday profiles. This turning point for maximum discharge from a cost perspective for lower rated BESSs can be calculated and visualised by plotting the CF over the full ES_{Pen} range. A CF dip (typically within low ES_{Pen} ranges) will be observed where energy costs start exceeding the demand savings.

3.4.5 *LCUS* breakeven concept

Equation (3.41) determines the cost breakeven point for the evaluation of the selected BESS where the yearly grid demand and TOU energy transfer cost savings equal the BESS discharge operational costs ($LCUS_{ES}$) where,

$$Cost_{Grid,ET} \geq Cost_{BESS}. \tag{3.41}$$

This statement will estimate the maximum $LCUS_{ES}$ to determine the preliminary BESS sizing from a costing perspective in conjunction with (2.2).

$Cost_{Grid.ET}$ from (3.41) is defined in (3.42) as,

$$Cost_{Grid,ET} = Cost_{Grid,D} + Cost_{Grid,ET,E} \tag{3.42}$$

where $Cost_{Grid,D}$ are the applicable costs related to the load maximum demand without DR integration calculated in (3.43) as,

$$Cost_{Grid,D} = \sum_{n=1}^{12} MD_{NDC,n} \cdot T_{NDC} + MD_{NAC} \cdot T_{NAC.} \tag{3.43}$$

$MD_{NDC,n}$ are the monthly maximum demands of the system and MD_{NAC} (equal to MD_{Load} without integration) the rolling yearly maximum demand.

$Cost_{Grid,ET,E}$ is the summation of seasonal energy costs related to the targeted BESS energy transfer area (example peak shaving or arbitrage) as shown in (3.44) for high demand, and (3.45) for low demand where,

$$Cost_{Grid,ET,E,H} = E_{Pk,H} \cdot T_{Pk,H} + E_{Std,H} \cdot T_{Std,H} + E_{OP,H} \cdot T_{OP,H} \tag{3.44}$$

$$Cost_{Grid,ET,E,L} = E_{Pk,L} \cdot T_{Pk,L} + E_{Std,L} \cdot T_{Std,L} + E_{OP,L} \cdot T_{OP,L} \tag{3.45}$$

with $E_{Pk,H}/E_{Pk,L}$, $E_{Std,H}/E_{Std,L}$, and $E_{OP,H}/E_{OP,L}$ the total high or low demand seasonal energy within the defined discharge area transferred to the BESS. $T_{Pk,H}/T_{Pk,L}$, $T_{Std,H}/T_{Std,L}$, and $T_{OP,H}/T_{OP,L}$ are the applicable high demand or low demand seasonal tariffs.

Operational $Cost_{BESS}$ from (3.41) is defined in (3.46) as,

$$Cost_{BESS} = Cost_{BESS,D} + Cost_{BESS,Disch} + Cost_{BESS,Chrge} \tag{3.46}$$

where $Cost_{BESS,D}$ are the applicable costs related to the new altered maximum demand shown in (3.47) as,

$$Cost_{BESS,D} = \sum_{n=1}^{12} MD_{DR,n} \cdot T_{NDC} + MD_{NAC,DR} \cdot T_{NAC} \tag{3.47}$$

where $MD_{DR,n}$ are the new monthly maximum demands of the system following BESS operation and $MD_{NAC,DR}$ the new rolling yearly maximum demand. This is similar to (2.4).

$Cost_{BESS,Disch}$ is the applicable cost related to the yearly BESS energy discharged to reduce the demand shown in (3.48) as,

$$Cost_{BESS,Disch} = ES_{Disch,y} \cdot LCUS_{ES} \tag{3.48}$$

with $ES_{Disch,y}$ the total yearly energy discharged by the BESS defined in (3.49), as the sum of the energy values of (3.44) and (3.45), as,

$$ES_{Disch,y} = E_{Pk,H} + E_{Std,H} + E_{OP,L} + E_{Pk,L} + E_{Std,L} + E_{OP,L}. \tag{3.49}$$

BESS recharge costs ($Cost_{BESS,Chrge}$) from the grid in the off-peak defined recharge t_{ch} period per season are calculated as the summation of the seasonal energy costs of (3.50) for high demand and (3.51) for low demand as,

$$Cost_{BESS,Chrge,H} = \frac{(E_{Pk,H} + E_{Std,H} + E_{OP,H}) \cdot T_{OP,H}}{BESS_{\eta}} \tag{3.50}$$

$$Cost_{BESS,Chrge,L} = \frac{(E_{Pk,L} + E_{Std,L} + E_{OP,L}) \cdot T_{OP,L}}{BESS_{\eta}} \tag{3.51}$$

with $BESS_{\eta}$ the roundtrip efficiency of the BESS as defined in (3.16).

By re-writing these equations, the maximum $LCUS_{ES}$ (discharge cost per kWh) can be determined by the terms in (3.52) so that,

$$LCUS_{ES,max} \leq Cost_{D} + Cost_{E} - Cost_{\eta} \tag{3.52}$$

where $Cost_D$ is the cost impact per energy discharged from demand changes calculated shown in (3.53) as,

$$Cost_{D} = \frac{\sum_{n=1}^{12}(MD_{NDC,n} - MD_{DR,n}) \cdot T_{NDC} + (MD_{NAC} - MD_{NAC,DR}) \cdot T_{NAC}}{ES_{Disch,y}}. \tag{3.53}$$

$Cost_E$ is the cost impact per energy discharged from the BESS and calculated as the sum of (3.54) and (3.55) where,

$$Cost_{E,H} = \frac{E_{Pk,H} \cdot (T_{Pk,H} \cdot BESS_{\eta} - T_{OP,H}) + E_{Std,H} \cdot (T_{Std,H} \cdot BESS_{\eta} - T_{OP,H})}{BESS_{\eta} \cdot ES_{Disch,y}}, \tag{3.54}$$

$$Cost_{E,L} = \frac{E_{Pk,L} \cdot (T_{Pk,L} \cdot BESS_{\eta} - T_{OP,L}) + E_{Std,L} \cdot (T_{Std,L} \cdot BESS_{\eta} - T_{OP,L})}{BESS_{\eta} \cdot ES_{Disch,y}}. \tag{3.55}$$

$Cost_{\eta}$ is the cost impact of off-peak operation and round-trip BESS efficiencies calculated in (3.56) as,

$$Cost_{\eta} = (E_{OP,H} \cdot T_{OP,H} + E_{OP,L} \cdot T_{OP,L}) \cdot \frac{(1 - BESS_{\eta})}{BESS_{\eta} \cdot ES_{Disch,y}}. \tag{3.56}$$

The maximum $LCUS_{ES}$ for a specific demand area (energy) transferred to the BESS can be determined from (3.52) at pre-feasibility stages to advise potential cost limitations and preliminary sizing, and can be extended to include yearly energy cost inflation rates as defined in (2.8) to (2.9). The model can further be extended to include the impacts of intermittent PV DG energy support to lower the BESS midday demand discharge required, and thereby reducing the E_{Pk}, E_{Std}, and E_{OP} (for recharge) terms of (3.49) for an increased $LCUS_{ES}$ range.

3.5 PROFILE CHANGES FROM INTEGRATED PV DG SYSTEMS

In previous research, PV penetration has been proposed as a demand reduction technique [23]. However, PV DG cannot permanently (and reliably) lower system designed demands since PV energy is not always generated at optimal output due to factors such as weather or other uncontrollable external factors. In contrast to other research, PV DG will be used as a supplementary energy source to support BESS peak shaving operation by lowering the required BESS discharge, recharging discharged BESS capacity (if surplus energy is available), and reducing the overall system payback period. Equation (3.57) illustrates the cost advantage of PV DG systems by comparing typical energy tariffs and PV system levelized energy system costs during the standard tariff midday period where,

$$LCOE_{PV} < T_{Std} < LCUS_{ES}. \tag{3.57}$$

PV DG targeting the standard tariff energy period at a lower levelized cost, when compared to grid and levelized BESS costs, will improve the overall system *CF* and open BESS capacities for peak tariff discharge.

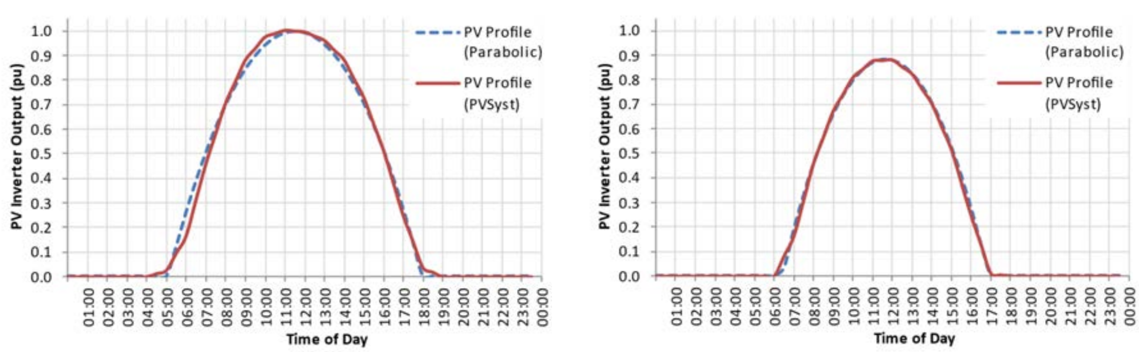
3.5.1 PV generation profiles

Two alternatives to solar profile modelling are investigated, namely a mathematical estimation approach and the utilisation of simulation software.

PV DG rated inverter output peaks are modelled as a percentage of the original load maximum demand (MD_{Load}) active power component, ranging from 0% (no generation) to the specified PV penetration (PV_{Pen}) level. Winter solar output profiles are lower compared to summer profiles, with a reduction in generation time and a generalised clear sky maximum of between 80% to 88% of maximum summer inverter outputs. Inverter output profiles are highly dependent on the site location (sun profile and climate) and panel installation trade-offs (azimuth and tilt). Matching with the case study location, summer clear sky PV generation times are selected from 05:00 to 18:00, and winter clear sky PV generation times from 06:30 to 17:00.

Solar profiles can be estimated mathematically (with some inaccuracies) as parabolic functions with three known points, namely start time (from zero generation), peak time (full generation), and end time (back to zero generation). Parabolic estimation assumes the peak output always occurs in the middle of the start and end times, which is practically dependent on the PV panel location, tilt, and azimuth. With the selected start and end points (generation time), as well as the varying peak penetration point defined, the unknown constants of the parabolic equation can be obtained for the three values a, b, and c. Alternatively, solar modelling software, such as PVSyst Photovoltaic Software, provides superior accuracy in generation profile representation based on location, installation, and system efficiencies.

Seasonal solar profiles (normalised to the maximum rated inverter output) are illustrated in Figure 3.11 and compares the mathematical and software approaches for South African PV systems at the location of the case study.



(a) (b)

Figure 3.11. Per unit seasonal inverter output of clear sky solar generation profiles.

(a) Estimation of summer PV inverter output. (b) Estimation of winter PV inverter output.

The amount of PV energy provided to the daily load can be estimated from (3.58) as,

$$DG_{PV} = \frac{2}{3} \cdot DG_{PV,pk} \cdot t_{PV} \cdot DG_{PV,\eta} \tag{3.58}$$

where DG_{PV} is the amount of energy provided by the PV inverter system with a peak of $DG_{PV,pk}$ (kWp) over a generation time of t_{PV} (hours). The efficiency factor of the PV system ($DG_{PV,\eta}$) considers the influence of sporadic weather and other system inefficiencies.

Although the parabolic approach shows promising output estimates for South African integration (except for the start and end times, which are practically dependent on installation variables), normalised PVSyst simulation outputs are selected and adjusted to the required penetration level to provide an accurate case study PV DG representation.

The following variables in Table 3.16 are defined as a per unit function of MD_{Load} to evaluate the impacts of increasing PV DG penetration levels.

Table 3.16 PV DG evaluation variables.

Variable	Unit	Description
MD_{Load}	kVA	Original load yearly Maximum/Peak Demand at the POC.
PV_{Pen}	%	Rated PV DG penetration level to MD_{Load}.
MD_{DR}	kVA/MD_{Load}	Revised Maximum Demand at the POC.
MD_T	hh:mm	Time of adjusted daily Maximum Demand.
LF	%	Load Factor.
PV_S	%	Ratio of surplus PV generated energy (demand < 0) over total generated PV energy. Over 5% generally indicates wastage.

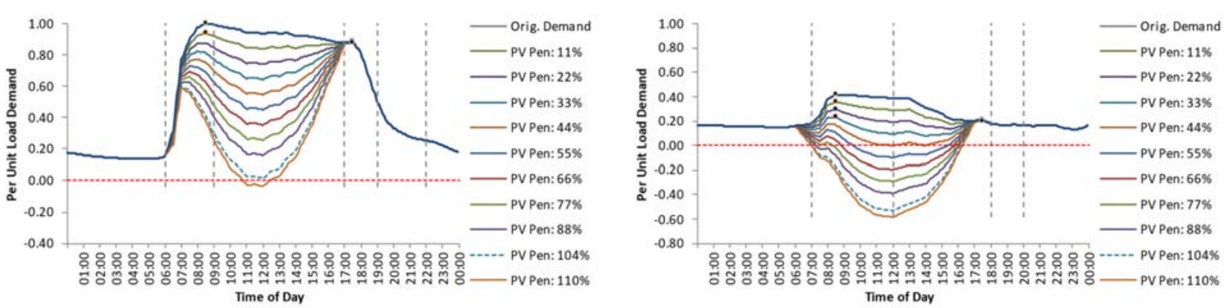
3.5.2 Profile simulations: PV DG integration

The impact of PV_{Pen} levels on commercial and residential profiles are modelled to validate results from previous research. Negative load demands indicate surplus energy that can be supplied back to the grid, provide BESS support, or lost (through RE curtailment) if network feed-in is unsupported.

PV generation profiles at inverter outputs are based on Figure 3.11 for high demand (winter) and low demand (summer) seasons, with maximum penetration levels (PV_{Pen}) rated as a percentage of the overall load active power component of the maximum demand. Possible grid feed-in as PV generated surplus is included to indicate potential BESS support functionality.

Commercial loads (PV DG):

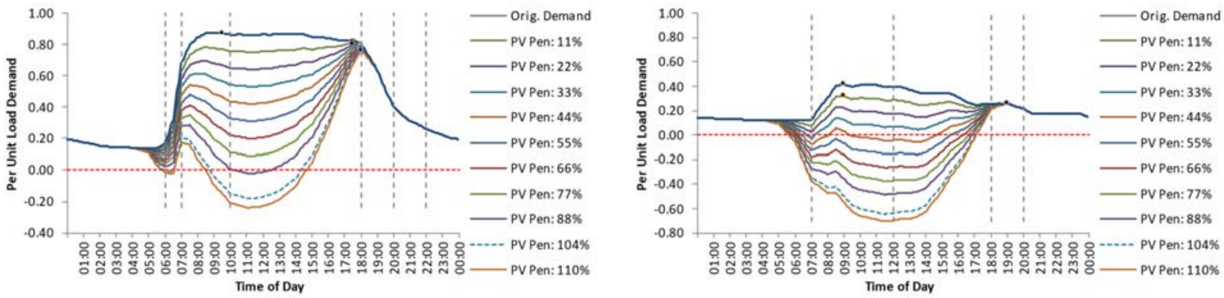
Figure 3.12 and Figure 3.13 illustrate the altered commercial load profiles implementing various levels of maximum rated output PV_{Pen} with changing maximum demands. Weekend profiles with low load maximums indicate high levels of surplus generated PV energy.



(a) (b)

Figure 3.12. Commercial high demand with levels of PV penetration.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 3.13. Commercial low demand with levels of PV penetration.

(a) Weekday demand. (b) Weekend demand.

Commercial results per unit of the original load maximum demand are shown in Table 3.17 (high demand, weekday), Table 3.18 (high demand, weekend), Table 3.19 (low demand, weekday), and Table 3.20 (low demand, weekend). PV surplus (PV_S) over 5% is highlighted as potential generation wastage.

Table 3.17 Commercial high demand weekday PV penetration results.

PV_{Pen}	0%	11%	22%	33%	44%	55%	66%	77%	88%	104%	110%
MD_{DR}	1.00	0.94	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
MD_T	08:30	08:30	17:30	17:30	17:30	17:30	17:30	17:30	17:30	17:30	17:30
LF	56.41%	57.14%	57.53%	54.37%	51.20%	48.03%	44.85%	41.67%	38.48%	33.84%	32.28%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.56%

Table 3.18 Commercial high demand weekend PV penetration results.

PV_{Pen}	0%	11%	22%	33%	44%	55%	66%	77%	88%	104%	110%
MD_{DR}	0.42	0.35	0.29	0.23	0.20	0.20	0.20	0.20	0.20	0.20	0.20
MD_T	08:30	08:30	08:30	08:30	17:30	17:30	17:30	17:30	17:30	17:30	17:30
LF	55.66%	57.46%	60.03%	63.97%	58.52%	52.51%	49.71%	47.87%	47.09%	46.59%	46.45%
PV_S	0.00%	0.00%	0.00%	0.00%	0.01%	**11.12%**	**22.40%**	**31.45%**	**39.19%**	**48.02%**	**50.70%**

Table 3.19 Commercial low demand weekday PV penetration results.

PV_{Pen}	0%	11%	22%	33%	44%	55%	66%	77%	88%	104%	110%
MD_{DR}	0.87	0.81	0.80	0.79	0.79	0.78	0.78	0.77	0.77	0.76	0.76
MD_T	09:30	17:30	17:30	18:00	18:00	18:00	18:00	18:00	18:00	18:00	18:00
LF	61.83%	61.36%	57.66%	53.21%	48.51%	43.75%	38.95%	34.09%	29.31%	25.70%	24.83%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.32%	**7.75%**	**10.94%**

Table 3.20 Commercial low demand weekend PV penetration results.

PV_{Pen}	0%	11%	22%	33%	44%	55%	66%	77%	88%	104%	110%
MD_{DR}	0.41	0.32	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
MD_T	09:00	09:00	19:00	19:00	19:00	19:00	19:00	19:00	19:00	19:00	19:00
LF	58.53%	63.98%	64.06%	48.86%	37.41%	34.58%	33.34%	32.57%	32.00%	31.37%	31.17%
PV_S	0.00%	0.00%	0.00%	0.25%	**6.50%**	**21.50%**	**33.24%**	**42.06%**	**48.83%**	**56.27%**	**58.52%**

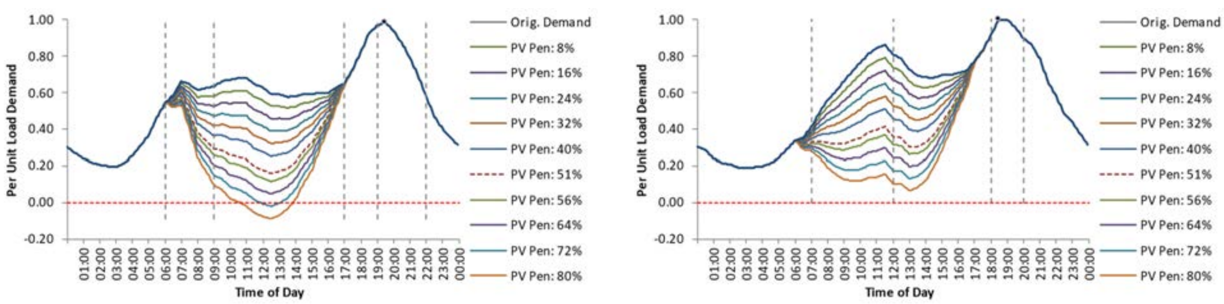
Results from increasing PV_{Pen} levels indicate a decrease in the profile maximum demands until the reduced and shifted maximum demands fall to the outside of the PV generation profile ranges. This is consistent with previous studies. The load factor will be improved at low PV_{Pen} levels (from a reduced maximum demand) but will worsen with increasing levels of PV_{Pen} due to the reduction of midday demands combined with unchanging shifted maximum/peak demands.

Depending on exact load profile forms, only high levels of PV_{Pen} could result in weekday PV generated surplus due to a good commercial demand to PV generation profile fit. A significant PV generation energy surplus is observed in weekend profiles, indicating that weekend commercial POCs will change to energy-sourcing nodes with medium levels of PV DG penetration. With network feed-in enabled, external network connected diversified loads can be supplied from the generated PV surplus albeit at a POC-bus voltage increase, or alternatively used more effectively internally in BESS support applications (Section 3.6).

Due to a good load to PV generation profile fit, high and low demand weekday *CF*s will indicate notable cost savings up to high levels of PV_{Pen}, proving the attractive feasibility of grid-tied PV DG systems within commercial applications as predicted by (3.57). Weekend profiles will show limited *CF* improvements, resulting from only small areas of standard tariffing energy arbitrage or potentially high magnitudes of PV generated surplus from low load demands. PV generated surplus of over 5% generally suggests generation wastage if T_{FI} is lower or similar to the $LCOE_{PV}$ and will not contribute to significant cost savings (assuming grid feed-in is supported) and will result in a flatlining/increasing *CF* at higher levels of PV_{Pen}. Should PV surplus feed-in be unsupported, a further *CF* incline will be seen at higher levels of PV_{Pen} as the surplus generation cost ($LCOE_{PV}$) will not contribute to any operational cost benefits.

Residential loads (PV DG):

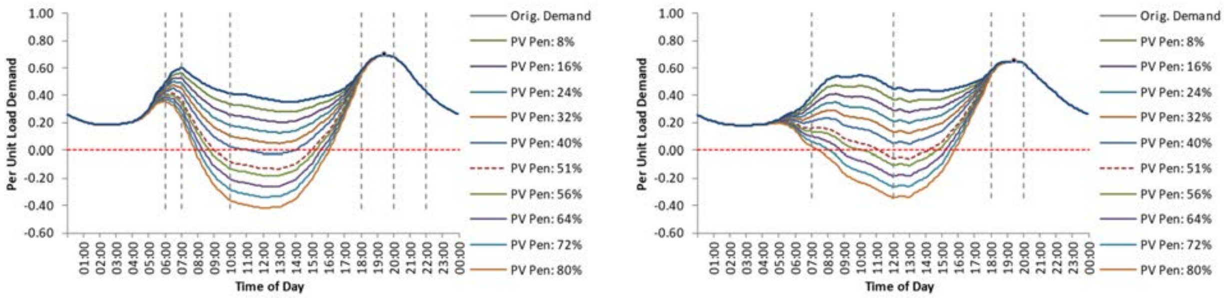
Figure 3.14 and Figure 3.15 illustrate the altered residential load profiles implementing various levels of maximum rated output PV_{Pen}. Low demand profiles with low midday demands indicate high levels of surplus generated PV energy.



(a) (b)

Figure 3.14. Residential high demand with levels of PV penetration.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 3.15. Residential low demand with levels of PV penetration.

(a) Weekday demand. (b) Weekend demand.

Residential results per unit of the original load maximum demand are shown in Table 3.21 (high demand, weekday), Table 3.22 (high demand, weekend), Table 3.23 (low demand, weekday), and Table 3.24 (low demand, weekend). PV surplus (PV_S) over 5% is highlighted as potential generation wastage.

Table 3.21 Residential high demand weekday PV penetration results.

PV_{Pen}	0%	8%	16%	24%	32%	40%	51%	56%	64%	72%	80%
MD_{DR}	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
MD_T	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30
LF	57.17%	55.08%	52.99%	50.90%	48.82%	46.73%	43.86%	42.55%	40.46%	38.43%	37.02%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.32%	3.51%

Table 3.22 Residential high demand weekend PV penetration results.

PV_{Pen}	0%	8%	16%	24%	32%	40%	51%	56%	64%	72%	80%
MD_{DR}	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
MD_T	18:30	18:30	18:30	18:30	18:30	18:30	18:30	18:30	18:30	18:30	18:30
LF	58.14%	56.09%	54.03%	51.98%	49.92%	47.87%	45.04%	43.76%	41.70%	39.65%	37.59%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 3.23 Residential low demand weekday PV penetration results.

PV_{Pen}	0%	8%	16%	24%	32%	40%	51%	56%	64%	72%	80%
MD_{DR}	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
MD_T	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30
LF	58.91%	54.79%	50.66%	46.54%	42.41%	38.57%	35.93%	35.11%	34.00%	33.11%	32.38%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	1.40%	**12.62%**	**17.56%**	**24.52%**	**30.50%**	**35.68%**

Table 3.24 Residential low demand weekend PV penetration results.

PV_{Pen}	0%	8%	16%	24%	32%	40%	51%	56%	64%	72%	80%
MD_{DR}	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
MD_T	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30
LF	63.19%	58.79%	54.39%	49.99%	45.59%	41.19%	35.87%	34.27%	32.65%	31.49%	30.68%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.58%	**6.09%**	**13.22%**	**19.93%**	**26.10%**

Results from increasing PV_{Pen} levels indicate that all residential maximum demands (and times) remain unchanged due to the load demand maximums not coinciding with PV generation profiles. The load factor will decrease with increasing levels of PV_{Pen} as a result of a reduction in midday demands with unchanging maximum/peak demands. Weekend residential profiles have a higher demand in the midday (due to a shift of the first morning peak) and will therefore have a better solar generation profile fit.

Depending on exact load profile forms, medium levels of PV_{Pen} will already result in PV generated surplus resulting from low midday demands and a poor load to PV generation profile fit. A significant PV generated energy surplus (over 5%) is observed in low demand (weekday and weekend) profiles from increased seasonal PV generation capability over lower summer load demands, indicating that low demand residential POCs could change to energy-sourcing nodes with medium levels of PV DG penetration. With network feed-in enabled, external network connected diversified loads can be supplied from the generated PV surplus albeit at a POC bus voltage increase, or alternatively used more effectively internally in BESS support applications (Section 3.6).

High and low demand weekday *CF*s will indicate notable cost savings only between low to medium levels of PV_{Pen} due to a generally poor load to PV generation profile fit. Weekend profiles, although a better load to PV generation profile fit, will also show limited *CF* improvements resulting from only small areas of standard tariffing energy arbitrage. Contrary to high demand profiles, low demand (with low midday demands) will show limited *CF* improvements resulting from potentially high magnitudes of PV generated surplus already expected from medium levels of penetration. PV generated surplus of over 5% generally suggests generation wastage if T_{FI} is lower or similar to the $LCOE_{PV}$ and will not contribute to significant cost savings (assuming grid feed-in is supported) and will result in a flatlining/increasing *CF* at higher levels of PV_{Pen}. Should PV surplus feed-in be unsupported, a further *CF* incline will be seen at higher levels of PV_{Pen} as the surplus generation cost ($LCOE_{PV}$) will not contribute to any operational cost benefits.

3.6 PROFILE CHANGES FROM INTEGRATED DR (PV DG & ES) SYSTEMS

The impacts of BESSs and PV DG systems were shown in the previous sections each with its own advantages, disadvantages, and limits. Combining the two technologies to amplify the benefits and support the limitations will result in the most optimal system integration parameters for consumer and utility benefit provided by DR technology synergism.

LV PV DG penetration (with the lowest LCOE) will be used as the primary source of load demand reduction and will provide energy cost savings by targeting the LV demand in mainly standard tariff periods. PV DG will also offer BESS support by reducing the required peak shaving discharge in the midday periods, providing a local energy source for BESS recharge (indirectly reducing the off-peak grid recharge demand), and generating surplus energy for possible grid feed-in potential. Internal network losses are reduced as the PV DG inverters are installed close to the individual LV load incomers.

BESS peak shaving operation (Section 3.4.4) is selected as the primary function to ensure a permanent POC maximum demand reduction and an improved load factor (utility benefit), while also providing the consumer with demand and energy savings by shifting the standard and peak tariff demands to the off-peak tariffing period through energy arbitrage. The BESS (with the support of the overall PV DG system) will provide additional savings by discharging any surplus capacity (either from seasonal spare, available/unused ES capacity following PV reduction of the allocated shaving demand, or from PV DG surplus capacity recharge) into peak tariff periods as limited by the PCS, PRR, and C-rate equipment ratings.

Following this approach, the advantages of Section 3.4.3 (Energy Arbitrage), Section 3.4.4 (Peak Shaving), and Section 3.5.2 (PV_{Pen} and energy surplus) are combined and governed by the DR control system. BESS standby operation (Section 3.4.2) can be included as an additional function where ample unused BESS capacity is available with high PV generation recharge capability, such as low demand residential consumers (Section 3.4.4). PV DG systems will be rated to avoid high levels of surplus external network feed-in, thereby limiting bi-directional power flow (and losses) locally within the internal consumer network. The overall system control will ensure that islanding and other integration protection, voltage levels, reactive power stability, and other connection requirements (as stated in the supply authority interconnection grid codes [34], [35]) are observed at the POC through measurements and control.

Considering TOU tariff scales, the *CF* defined in (2.3), surplus power flow limitations, and prioritising cheaper $LCOE_{PV}$ over the more expensive $LCUS_{ES}$ discharge, the best network benefits and consumer payback periods will be realised by positioning the DR units similar to Figure 1.1b such that:

- Multiple LV PV DG systems installed at the individual distributed loads.
- A single BESS (including modular switchgear) installed close to the POC.
- Reactive power compensators installed close to the BESS (as required).

3.6.1 Conceptual DR design parameters, operation, and control

The combined DR system design and power flow guideline of Figure 3.16 illustrates conceptual operation and demand profile changes following selected DR sizing and control parameters. Subsections of Figure 3.16 include Figure 3.17 for fundamental BESS sizing and control selection, Figure 3.18 for fundamental PV DG system sizing, Figure 3.19 for BESS active power cycle control, and Figure 3.20 for DG surplus control.

Load profile variances and high PV_{Pen} support will result in high demand peak shaving rated BESSs being oversized in lower load demand profiles resulting in unused ES capacity. To utilise this capacity, BESS management will continuously monitor the unused/surplus ES capacity status by conducting a comparative measurement analysis to historic load and discharge databases to estimate and update the time-based seasonal (high demand, low demand) daily (weekday, weekend) peak shaving discharge capacity required without PV DG support. This predicted and reserved capacity (ES_R) is then used to estimate the available surplus capacity during the specific operational day as shown in (3.59) and (3.60) as,

$$Capacity_{Surplus} = Capacity_{Rated,Spare} + Capacity_{Operational,Spare} \tag{3.59}$$

or,

$$ES_{S,n} = \left(ES_{Cap} \cdot ES_{DoD} - ES_R\right) \cdot SF_S + \sum_{n=1}^{N} \left(ES_{R,n} - ES_{Ops,n} - ES_{S,Disch,n}\right) \tag{3.60}$$

where $ES_{S,n}$ is the available surplus energy not required for peak shaving (up to the time of day) that could be discharged as additional peak tariff energy arbitrage. ES_{Cap} is the rated BESS capacity, ES_{DoD} the defined ES depth of discharge, and ES_R the total daily capacity reserved for the primary function peak shaving discharge as estimated from historical database estimations that exclude PV support. N is the total measurement points, calculated by dividing the daily hours (T) by the measurement interval time t (in hours). $ES_{R,n}$ is the daily reserved capacity to time, $ES_{Ops,n}$ the actual ES operational discharge to time (including the impact of PV DG demand takeover and recharge), and $ES_{S,Disch,n}$ the previously discharged spare capacity up to measurement point n. The SF_S is a utilisation factor in the range of,

$$0 \leq SF_S \leq 100\% \tag{3.61}$$

as an additional measure to prevent unexpected BESS recharge demand increases over the maximum shaving setpoint if historical data is unavailable or too limited for accurate ES_R predictions. A high SF_S maximises spare capacity discharge (as historical database accuracy improves for precise control predictions), where a lower value omits rated capacity variance. Surplus discharge ramp rates remain controlled within PRR limits as peak tariff periods are fixed, irrespective of available surplus ($ES_{S,n}$). Implementing BESS surplus discharge operation ensures maximised ES_{Cap} utilisation from operational spare ES capacities, such as spare ES capacity being available in low demand seasons with high seasonal PV generation output/surplus capability, opposed to high demand seasons with lower BESS spare capacity available and lower seasonal PV generation output (Figure 3.11).

Additional to Section 3.4.1 and above, BESS ratings and operational limits (governed by control), include:

- BESSs shall be rated for primary function peak shaving, without PV DG support (Section 3.4.4 and Figure 3.17).
- BESSs shall operate in pre-defined (programmed) time periods.
- BESS control shall continuously predict ESR for secondary function surplus energy arbitrage (Equation (3.60) and Figure 3.19).
- BESSs cannot anticipate future events (such as PV DG drop), and capacity remains reserved for primary function operation.
- BESS recharge is PV DG surplus prioritised (Figure 3.20), followed by off-peak grid recharge (Figure 3.19).
- BESS grid recharge in peak or standard tariff periods is prohibited.
- BESS overcharging is prohibited.
- BESS discharge into the external grid, as a surplus, is blocked (Figure 3.19).
- Operation remains limited by ES_{PCS}, ES_{Cap}, ES_C, $BESS_\eta$, ES_{DoD}, ES_{PRR}, and Control.

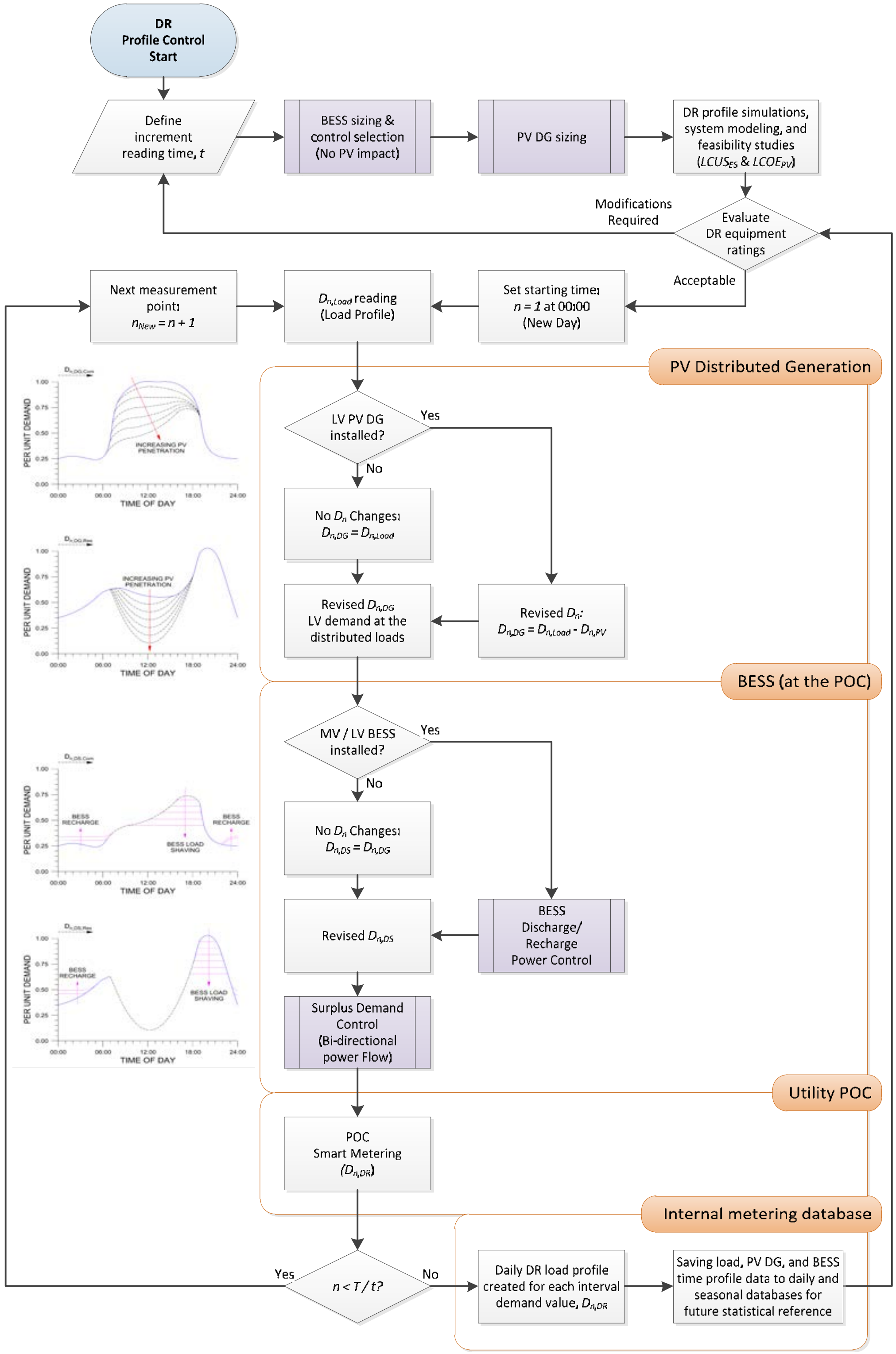


Figure 3.16. Changing DR POC demand profile methodology (Simplified).

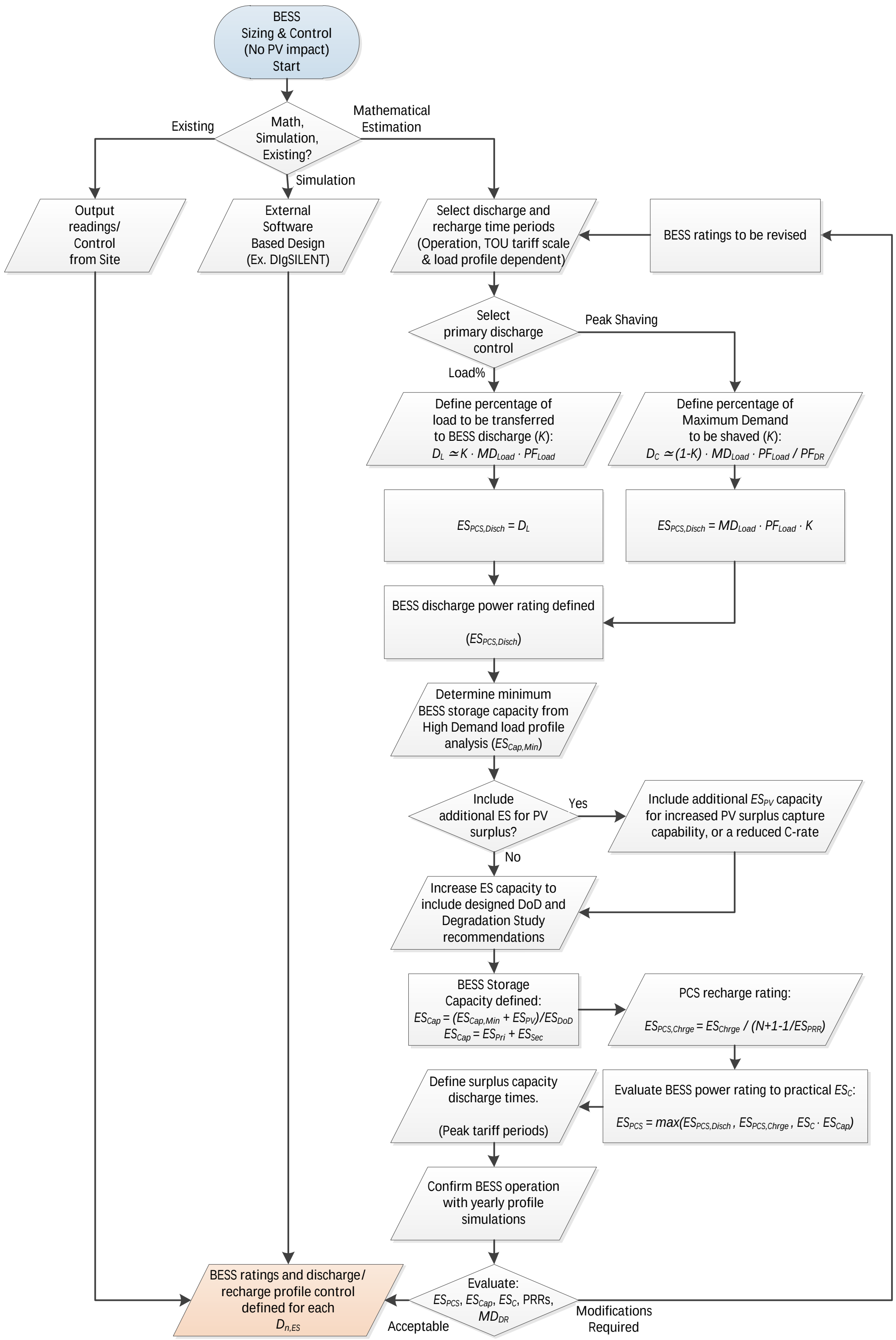


Figure 3.17. BESS sizing and control selection (Simplified).

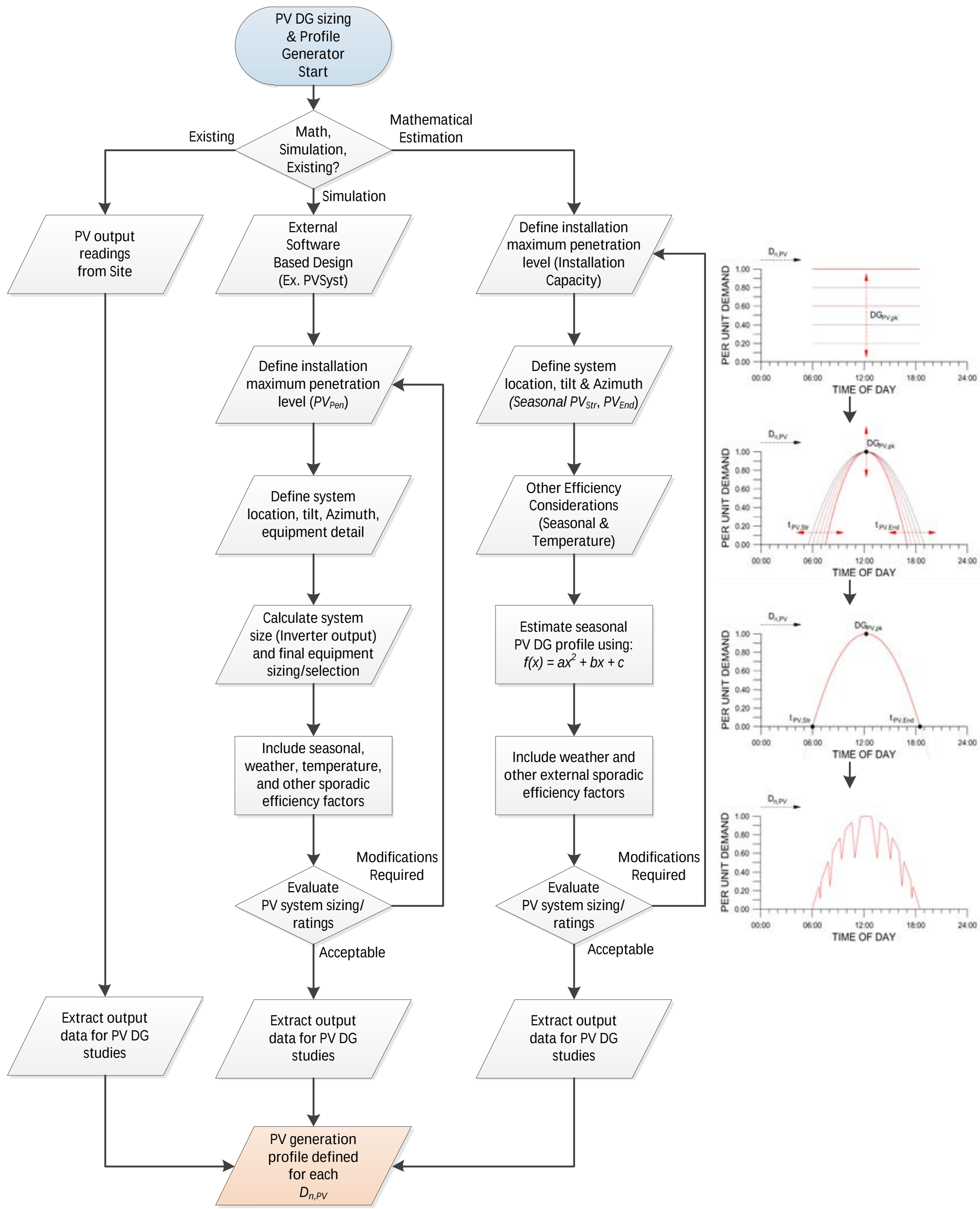


Figure 3.18. PV DG sizing and generation profile (Simplified).

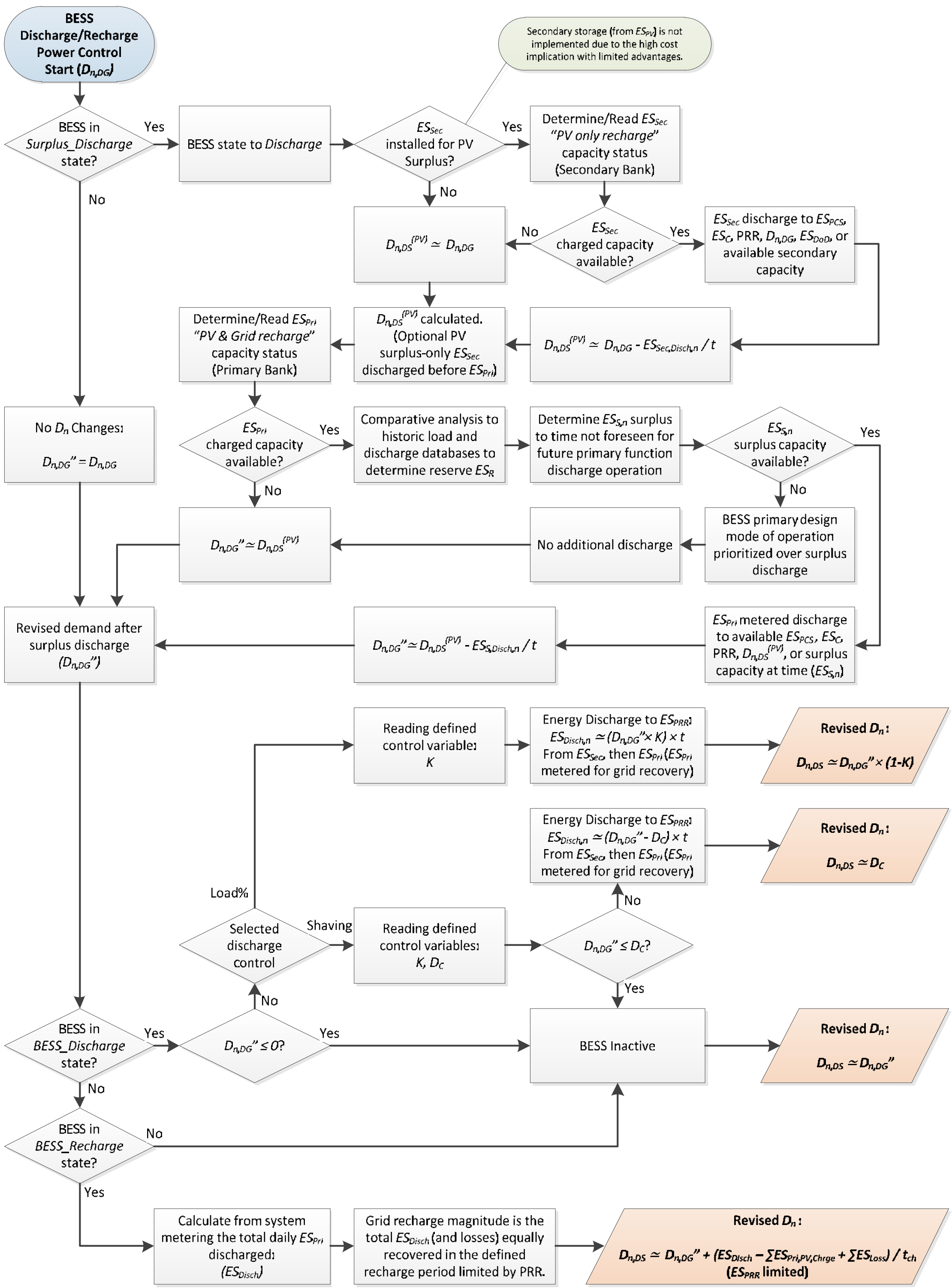


Figure 3.19. BESS discharge and recharge control (Simplified).

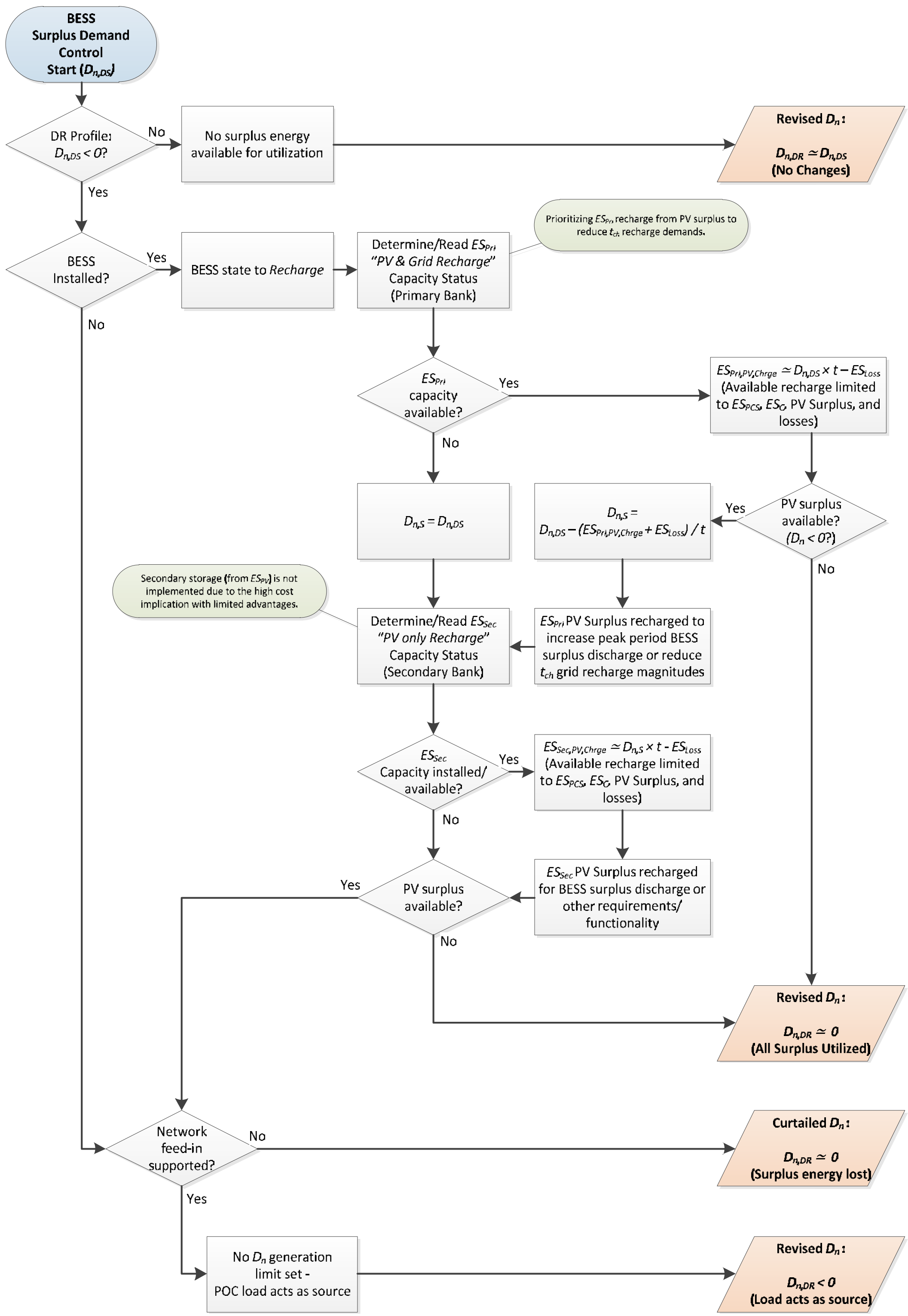


Figure 3.20. DG surplus control, BESS support, and surplus feed-in (Simplified).

For profile evaluation, the criteria of Table 3.2 (BESS) and Table 3.16 (PV DG) will be used in combination with the new per unit evaluation variables defined in Table 3.25.

Table 3.25 DR evaluation variables.

Variable	Unit	Description
ES_{Util}	%	Ratio of utilised ES capacity to rated capacity. A value of 100% signifies full ES_{Cap} utilisation to ES_{DOD} limits in the worst-case profile scenario.
ES_S	kWh/MD_{Load}	ES capacity charged but unused daily surplus at the end of the daily discharge period, following seasonal spare capacity, PV load takeover, or PV surplus recharge as described in (3.60).

The daily remainder of charged surplus capacity (ES_S) will increase at higher levels of PV_{Pen} from PV DG surplus capture or equipment and control discharge limitations. This surplus capacity can be utilised for other applications, such as providing a dedicated back-up resource to ensure supply/critical-load redundancy or extend BESS lifetime through reduced discharge cycles. To reduce the ES_S variable, higher levels of ES surplus can be discharged by increasing the BESS equipment's C-rate, PRR, or PCS ratings.

Storage capacity can be oversized with a dedicated system for capturing higher levels of PV DG surplus to be discharged as peak tariff period energy arbitrage or other applications. This optional consideration is motivated by the potential presence of high levels of PV DG surplus being curtailed offering low (if any) feed-in financial gains, and a reducing $LCOE_{PV}$ predicted compared to rising off-peak tariff energy costs. To maximise the financial benefits from BESS storage capacity oversizing dedicated to PV DG surplus capture, $LCUS_{ES}$ should be lower for higher rated systems, higher grid TOU energy costs, lower $LCOE_{PV}$ compared to T_{OP}, and low losses (short distances) between the PV DG (at the LV distributed loads) and BESS (at the POC) DR components. If these conditions are satisfied and combined with an increased PCS rating (to an acceptable increased C-rate), higher levels of energy discharge will be possible for additional energy cost savings. However, considering the inexpensive nature of PV DG systems when compared to

BESSs, that the costliest component of BESSs will be larger, and that a significant amount of unused ES_{Cap} is already available in low demand seasons, additional PV DG surplus capture will remain an operational bonus rather than a deciding factor for determining system ratings. These secondary PV DG surplus capture storage capacities and operation, defined as ES_{Sec}, are included in the conceptual control diagrams for future consideration or extension for full off grid applications.

3.6.2 Profile simulations: DRs including PV DG, BESS, and DR Control

To determine the maximum impact of a hybrid DR system, the highest amount of BESS peak shaving calculated in Section 3.4.4 (without PV DG support) is selected for the best load factor and lowest profile demand. The approach followed in this section can be repeated to Figure 3.16 for any BESS ratings should practical and financial feasibility studies recommend an alternative peak shaving demand setpoint for a lower rated BESS (considering the high cost of BESSs). Surplus feed-in is disabled (and financial benefits from energy export excluded in *CF* comparisons) to localise bi-directional power flow within the internal network as grid feed-in is not always possible and that the average applicable feed-in tariffs (although a good additional benefit) not being realistically profitable at the time. For comparison, graphical POC load profiles in this section are scaled to a similar demand y-axis as used in Section 3.5.2 and indicate possible surplus generated capacities for magnitude visualisation.

Commercial systems are rated to Table 3.26 (32% BESS peak shaving), and residential systems to Table 3.31 (32% BESS peak shaving) to enforce a permanently reduced MD_{DR} maximum demand of 68% or lower when compared to the original POC maximum demand even if varying/intermittent PV DG is not generating at full output as a result of weather or other external causes. By selecting an ES_C of 0.2 (typical for MWh-rated BESSs [112]) the minimum PCS ratings are increased from Table 3.9 and Table 3.12 to the ratings defined in Table 3.26 and Table 3.31 respectively as per (3.29). BESS discharge and recharge periods remain as defined in Section 3.4.4 with the additional energy arbitrage functionality of the available BESS surplus discharge occurring in the weekday peak tariff periods as defined in (3.60).

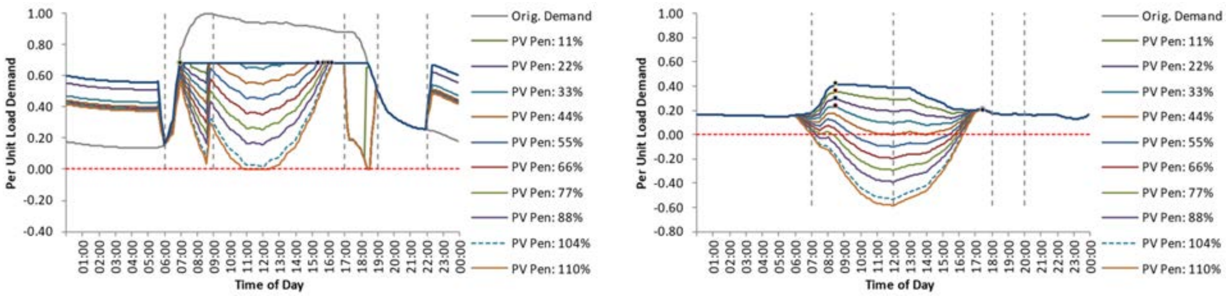
Commercial loads (PV DG & BESS):

Figure 3.21 and Figure 3.22 illustrate the altered commercial load profiles implementing maximum peak shaving and increasing levels of PV_{Pen}. Commercial BESS ratings installed are summarised in Table 3.26.

Table 3.26 Maximised per unit commercial BESS peak shaving ratings and control.

Variable	Setpoint	Unit	Description
ES_{Pen}	32	%	Maximum peak demand shaved by the BESS (K).
D_C	0.68	kVA/MD_{Load}	BESS maximum demand shaving setpoint for $MD_{DR.}$
ES_{Cap}	3.44	kWh/MD_{Load}	BESS capacity rating for 80% ES_{DoD}.
ES_{PCS}	0.69	kW/MD_{Load}	BESS PCS rating for a practical ES_C of 0.20. (63% increase from Table 3.9)
ES_{PRR}	20	%	Maximum BESS 5-minute power ramp rate.
Discharge (Weekday)	06:00 - 22:00	hh:mm	Weekday BESS discharge-enable for peak shaving.
Discharge (Weekend)	Inactive	hh:mm	Weekend BESS discharge-enable for peak shaving.
Recharge (Weekday)	22:00 - 06:00	hh:mm	Weekday BESS recharge period t_{ch}.
Recharge (Weekend)	Inactive	hh:mm	Weekend BESS recharge period t_{ch}.

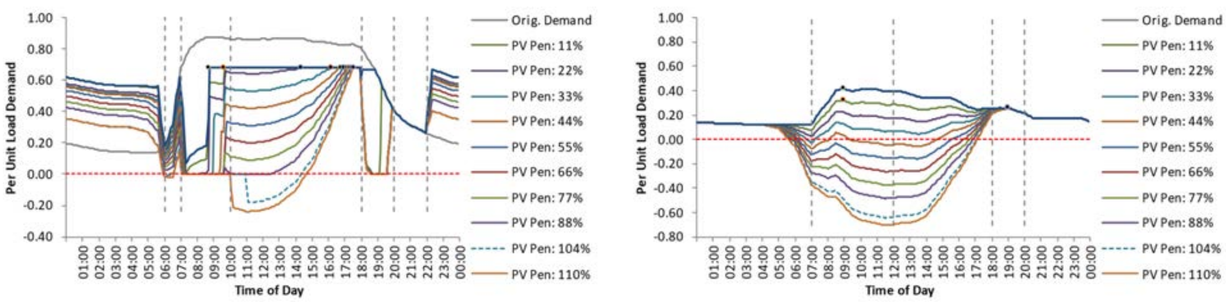
The maximum value of BESS peak shaving for the best load factor is implemented at the POC, ensuring a maximum MD_{DR} of 0.68 to the original load POC maximum demand. BESS surplus discharge (in arbitrage operation) is enabled on weekdays and seen as the additional demand reduction during profile peak tariff periods. Weekend profiles, with low load maximums, do not require BESS peak shaving discharge and indicate high levels of PV generation surplus.



(a) (b)

Figure 3.21. Commercial high demand, peak shaved, with levels of PV penetration.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 3.22. Commercial low demand, peak shaved, with levels of PV penetration.

(a) Weekday demand. (b) Weekend demand.

Commercial results per unit of the original load maximum demand are shown in Table 3.27 (high demand, weekday), Table 3.28 (high demand, weekend), Table 3.29 (low demand, weekday), and Table 3.30 (low demand, weekend). PV surplus (PV_S) over 5% is highlighted as potential generation wastage.

Table 3.27 Commercial high demand weekday BESS shaved with PV penetration.

PV_{Pen}	**0%**	**11%**	**22%**	**33%**	**44%**	**55%**	**66%**	**77%**	**88%**	**104%**	**110%**
MD_{DR}	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
MD_T	06:55	07:00	07:00	07:00	07:00	15:25	15:45	15:55	16:05	16:15	16:15
LF	85.94%	81.78%	77.29%	72.56%	68.21%	64.00%	59.81%	55.63%	51.46%	45.40%	43.13%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ES_{Util}	100%	100%	89%	70%	63%	61%	60%	59%	58%	58%	56%
ES_S	0.00	0.00	0.31	0.84	1.02	1.08	1.11	1.13	1.15	1.16	1.20
ES_{CRR}	12.28%	12.28%	10.91%	8.53%	7.73%	7.48%	7.34%	7.24%	7.17%	7.09%	6.92%

Table 3.28 Commercial high demand weekend BESS shaved with PV penetration.

PV_{Pen}	**0%**	**11%**	**22%**	**33%**	**44%**	**55%**	**66%**	**77%**	**88%**	**104%**	**110%**
MD_{DR}	0.42	0.35	0.29	0.23	0.20	0.20	0.20	0.20	0.20	0.20	0.20
MD_T	08:30	08:30	08:30	08:30	17:30	17:30	17:30	17:30	17:30	17:30	17:30
LF	55.66%	57.46%	60.03%	63.97%	58.52%	52.51%	49.71%	47.87%	47.09%	46.59%	46.45%
PV_S	0.00%	0.00%	0.00%	0.00%	0.01%	**11.12%**	**22.40%**	**31.45%**	**39.19%**	**48.02%**	**50.70%**
ES_{Util}	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
ES_S	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.76
ES_{CRR}	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 3.29 Commercial low demand weekday BESS shaved with PV penetration.

PV_{Pen}	0%	11%	22%	33%	44%	55%	66%	77%	88%	104%	110%
MD_{DR}	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
MD_T	08:45	09:40	14:20	16:10	16:45	17:00	17:10	17:20	17:25	17:30	17:35
LF	82.25%	76.47%	70.41%	64.54%	58.73%	52.79%	46.76%	40.73%	34.72%	28.65%	27.94%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.78%	**8.91%**
ES_{Util}	100%	100%	90%	87%	86%	80%	72%	63%	55%	37%	37%
ES_S	0.00	0.00	0.26	0.35	0.39	0.55	0.78	1.01	1.25	1.72	1.73
ES_{CRR}	12.28%	12.28%	11.11%	10.70%	10.53%	9.84%	8.79%	7.77%	6.71%	4.60%	4.59%

Table 3.30 Commercial low demand weekend BESS shaved with PV penetration.

PV_{Pen}	0%	11%	22%	33%	44%	55%	66%	77%	88%	104%	110%
MD_{DR}	0.41	0.32	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
MD_T	09:00	09:00	19:00	19:00	19:00	19:00	19:00	19:00	19:00	19:00	19:00
LF	58.53%	63.98%	64.06%	48.86%	37.41%	34.58%	33.34%	32.57%	32.00%	31.37%	31.17%
PV_S	0.00%	0.00%	0.00%	0.25%	**6.50%**	**21.50%**	**33.24%**	**42.06%**	**48.83%**	**56.27%**	**58.52%**
ES_{Util}	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
ES_S	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.76
ES_{CRR}	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

The BESS ensures that the new POC maximum demand remains limited to 68% of the original load POC maximum demand at no or poor PV_{Pen} by targeting weekday midday demand peaks. C-rates are well within the limits for any PV_{Pen} level due to the high amount of maximum rated ES capacity installed. Initially, spare ES capacity is not available in high demand weekday profiles without PV generation as all the capacity remains dedicated to full peak shaving discharge operation (control is unable to predict a reduction in future PV generation). Low demand weekdays will have spare storage capacity available from the start of the day (not required for full peak shaving operation) that is utilised for peak tariff arbitrage operation.

The new weekday maximum demand will remain the same as the increasing PV generation profile (coinciding well with typical commercial load profiles) reduces the load demands/peaks originally targeted for BESS peak shaving. This frees up BESS capacity to be discharged as a surplus during peak tariff periods and provides additional energy cost savings through energy arbitrage operation, limited by the available surplus at the time and BESS equipment ratings (PCS, PRR, C-rate). Off-peak ES recharge period demand reduction is not seen if the total discharged ES capacity (that includes surplus peak tariff arbitrage operation) can only be recuperated from the grid. Increasing PV_{Pen} will reduce the daily BESS recharge required ultimately allowing for a reduced ES_{CRR} value as per (3.23).

By further increasing PV_{Pen} at the load to surplus status, any discharged ES capacity will be recharged followed by external network export if the BESS is fully charged, a surplus occurs from BESS rating recharge limitations, or lost (through RE curtailment) if feed-in is unsupported. BESS recharge from surplus PV DG will result in a reduction of the afternoon peak tariff demands (owing to additional recharged ES capacity now available) or a demand reduction in the off-peak recharge period should the PV DG surplus recharge capacities not be able to fully discharge during the afternoon peak tariff period.

Plotting the changing *CF* to increasing PV DG penetration levels will indicate an improving *CF* from low $LCOE_{PV}$ taking over increasing levels of weekday midday load demand originally selected for BESS peak shaving or grid TOU tariffing. This allows the BESS to focus on weekday peak tariff energy arbitrage for better savings. Weekend profiles, with high levels of unused PV DG surplus, will worsen the *CF* should grid feed-in be disabled. Supporting Section 3.5.2, *CF* graphs will show that PV DG surplus over 5% will not contribute to energy cost savings. With expected energy tariff increases, and DR equipment becoming more affordable, cumulative yearly savings within the operational lifetime of the DR systems will demonstrate improved cost savings with future tariff *CF* estimations.

Optimal profile PV_{Pen} ratings will be based on low demand weekday profiles, considering that low demand weekday profiles are expected most of the year and that generation surplus does not provide any significant cost benefits. Low demand maximum unused PV generation surplus will be limited to around 5% to counter future system degradation and generation irregularities (even-though high demand weekday profiles will show improved *CF* values at higher penetration levels). Maximum PV_{Pen} will therefore be selected as 104%, supporting the maximum sized BESS ratings (ensuring the lowest consistent maximum demand possible for the best load factor and utility strain relief) as defined in Table 3.26 for the case study.

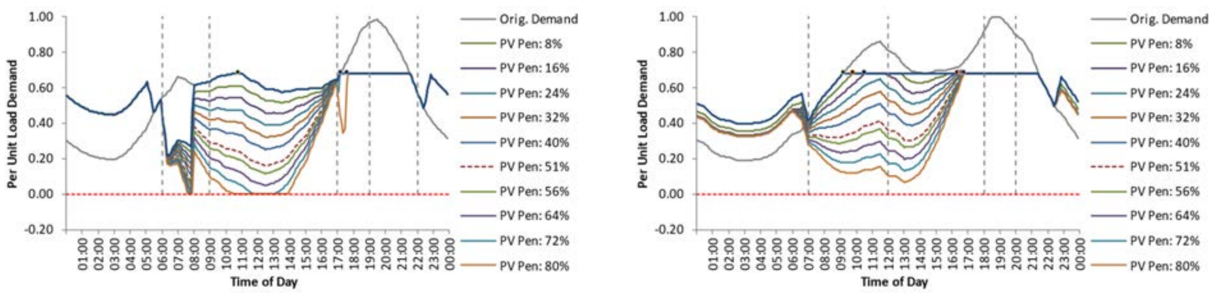
Residential loads (PV DG & BESS):

Figure 3.23 and Figure 3.24 illustrate the altered residential load profiles implementing maximum peak shaving and increasing levels of PV_{Pen}. Residential BESS ratings installed are summarised in Table 3.31.

Table 3.31 Maximised per unit residential BESS peak shaving ratings and control.

Variable	Setpoint	Unit	Description
ES_{Pen}	32	%	Maximum peak demand shaved by the BESS (*K*).
D_C	0.68	kVA/MD_{Load}	BESS maximum demand shaving setpoint for MD_{DR}.
ES_{Cap}	1.79	kWh/MD_{Load}	BESS capacity rating for 80% ES_{DoD}.
ES_{PCS}	0.36	kW/MD_{Load}	BESS PCS rating for a practical ES_C of 0.20. (12% increase from Table 3.12)
ES_{PRR}	20	%	Maximum BESS 5-minute power ramp rate.
Discharge (Weekday)	06:00 - 22:00	hh:mm	Weekday BESS discharge-enable for peak shaving.
Discharge (Weekend)	07:00 - 22:00	hh:mm	Weekend BESS discharge-enable for peak shaving.
Recharge (Weekday)	22:30 - 05:30	hh:mm	Weekday BESS recharge period t_{ch}.
Recharge (Weekend)	22:30 - 07:00	hh:mm	Weekend BESS recharge period t_{ch}.

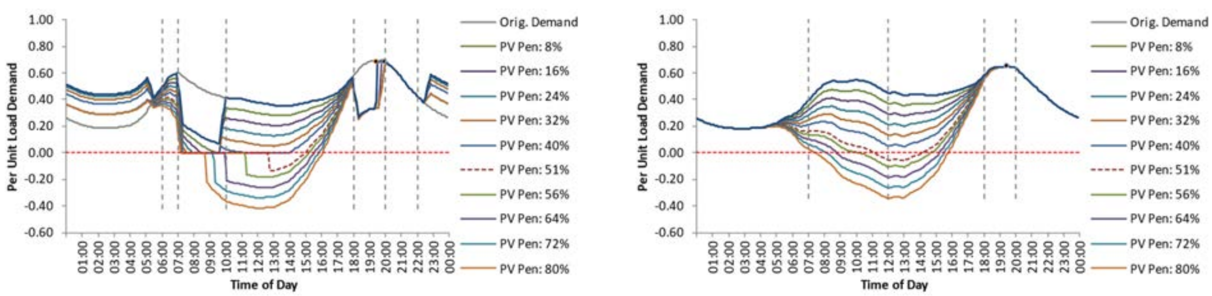
The maximum value of BESS peak shaving for the best load factor is implemented at the POC, ensuring a maximum MD_{DR} of 0.68 to the original load POC maximum demand. BESS surplus discharge (in arbitrage operation) is enabled on weekdays and seen as the additional demand reduction during profile peak tariff periods, increasing BESS viability in low demand weekday profiles. Low demand profiles, with load maximums marginal or below the peak shaving setpoint, require minimal levels of BESS peak shaving discharge and utilises surplus capacity for peak tariff arbitrage operation.



(a) (b)

Figure 3.23. Residential high demand, peak shaved, with levels of PV penetration.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 3.24. Residential low demand, peak shaved, with levels of PV penetration.

(a) Weekday demand. (b) Weekend demand.

Residential results per unit of the original load maximum demand are shown in Table 3.32 (high demand, weekday), Table 3.33 (high demand, weekend), Table 3.34 (low demand, weekday), and Table 3.35 (low demand, weekend). PV surplus (PV_S) over 5% is highlighted as potential generation wastage.

Table 3.32 Residential high demand weekday BESS shaved with PV penetration.

PV_{Pen}	0%	8%	16%	24%	32%	40%	51%	56%	64%	72%	80%
MD_{DR}	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
MD_T	10:50	17:15	17:15	17:15	17:15	17:15	17:15	17:15	17:15	17:15	17:40
LF	84.25%	81.23%	78.20%	75.18%	72.16%	69.14%	64.98%	63.10%	60.07%	57.07%	54.19%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ES_{Util}	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
ES_S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
ES_{CRR}	14.12%	14.11%	14.11%	14.11%	14.11%	14.10%	14.10%	14.10%	14.10%	14.09%	14.06%

Table 3.33 Residential high demand weekend BESS shaved with PV penetration.

PV_{Pen}	0%	8%	16%	24%	32%	40%	51%	56%	64%	72%	80%
MD_{DR}	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
MD_T	09:15	09:50	10:35	16:25	16:35	16:35	16:40	16:40	16:45	16:45	16:45
LF	87.05%	83.71%	80.51%	77.45%	74.43%	71.40%	67.25%	65.36%	62.33%	59.31%	56.29%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ES_{Util}	100%	80%	68%	66%	66%	65%	65%	65%	65%	65%	65%
ES_S	0.00	0.29	0.46	0.49	0.49	0.49	0.50	0.50	0.50	0.50	0.50
ES_{CRR}	11.52%	9.20%	7.86%	7.59%	7.56%	7.54%	7.51%	7.50%	7.49%	7.48%	7.46%

Table 3.34 Residential low demand weekday BESS shaved with PV penetration.

PV_{Pen}	0%	8%	16%	24%	32%	40%	51%	56%	64%	72%	80%
MD_{DR}	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
MD_T	19:30	19:30	19:50	20:00	20:00	20:00	20:00	20:00	20:00	20:00	20:00
LF	61.52%	57.32%	53.12%	48.83%	44.49%	40.13%	35.41%	34.90%	34.20%	33.60%	33.08%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.64%	**11.63%**	**20.82%**	**28.16%**	**34.21%**
ES_{Util}	100%	100%	100%	94%	85%	72%	42%	42%	42%	42%	42%
ES_S	0.00	0.00	0.00	0.08	0.21	0.40	0.83	0.83	0.83	0.83	0.83
ES_{CRR}	14.11%	14.11%	14.11%	13.33%	12.00%	10.19%	5.88%	5.88%	5.88%	5.88%	5.88%

Table 3.35 Residential low demand weekend BESS shaved with PV penetration.

PV_{Pen}	0%	8%	16%	24%	32%	40%	51%	56%	64%	72%	80%
MD_{DR}	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
MD_T	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30	19:30
LF	63.19%	58.79%	54.39%	49.99%	45.59%	41.19%	35.87%	34.27%	32.65%	31.49%	30.68%
PV_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.58%	**6.09%**	**13.22%**	**19.93%**	**26.10%**
ES_{Util}	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
ES_S	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
ES_{CRR}	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

The BESS ensures that the new POC maximum demand remains limited to 68% of the original load POC maximum demand at no or poor PV_{Pen} by targeting residential load peaks in the mornings and late afternoons. Residential load maximums do not coincide with PV generation profiles, and an increase in PV_{Pen} will not contribute to a reduced residential maximum demand, thereby highlighting BESS interdependency for permanent maximum demand reduction in notably high demand seasons. C-rates are well within the limits for any PV_{Pen} level due to the high amount of rated ES capacity installed. Initially, significant spare capacities are available in weekday profiles (resulting from high demand weekend rated BESSs) that are utilised for additional energy cost savings through energy arbitrage operation, notable during weekday morning peak tariff period demand reductions as limited by the available surplus at the time and BESS equipment ratings (PCS, PRR, C-rate). Only a small portion of designated BESS shaving demands is taken over by the increasing levels of PV generation to free up ES capacity for afternoon peak tariff surplus discharge. Off-peak ES recharge period demand reduction is not seen if the total discharged ES capacity (that includes surplus peak tariff arbitrage operation) can only be recuperated from the grid. Increasing PV_{Pen} will reduce the daily BESS recharge required ultimately allowing for a reduced ES_{CRR} value as per (3.23).

By further increasing PV_{Pen} at the load to surplus status, any discharged ES capacity will be recharged followed by external network export if the BESS is fully charged, a surplus occurs from BESS rating recharge limitations, or lost (through RE curtailment) if feed-in is unsupported. BESS recharge from surplus PV DG will result in a reduction of the afternoon peak tariff demands (owing to additional recharged ES capacity now available) or a demand reduction in the off-peak recharge period should the PV DG surplus recharge capacities not be able to fully discharge during the afternoon peak tariff period.

Plotting the changing CF to increasing PV DG penetration levels will indicate an improving CF from low $LCOE_{PV}$ taking over increasing levels of weekday midday load demand originally selected for BESS peak shaving or grid TOU tariffing. This allows the BESS to focus on weekday peak tariff energy arbitrage for better savings. Low demand profiles, with high levels of unused PV DG surplus, will worsen the CF should grid feed-in be disabled. Supporting Section 3.5.2, CF graphs will show that PV DG surplus over 5% will not contribute to energy cost savings. With expected energy tariff increases, and DR equipment becoming more affordable, cumulative yearly savings within the operational lifetime of the DR systems will demonstrate improved cost savings with future tariff CF estimations.

Optimal profile PV_{Pen} ratings will be based on low demand weekday profiles, considering that low demand weekday profiles are expected most of the year and that generation surplus does not provide any significant cost benefits. Low demand maximum unused PV generation surplus will be limited to around 5% to counter future system degradation and generation irregularities (even-though high demand weekday profiles will show improved *CF* values at higher penetration levels). Maximum PV_{Pen} will therefore be selected as 51%, supporting the maximum sized BESS ratings (ensuring the lowest consistent maximum demand possible for the best load factor and utility strain relief) as defined in Table 3.31 for the case study.

3.7 CHAPTER SUMMARY

In this Chapter an overview of DR integration profile modelling was provided for typical characteristic reticulation load profile types. The individual impacts of integrated BESSs and/or PV DG on these load profiles were evaluated and combined to determine the optimal DR system rating factors (BESS and PV DG) as supported by the developed conceptual power flow control algorithms prior to the case study verification in Chapter 4.

In Section 3.2 it was found that consumer load profiles (commercial and residential) and load factors can be estimated from first principles. In Section 3.3, measured load profile models were used to determine the general differences in seasonal weekday and weekend load demands. The per unit profiles determined in this section were used as baseline consumer load profiles prior to the integration of BESSs and/or PV DG. Section 3.4 investigated the impacts of BESSs by defining the associated BESS rating factors and limits by simulating various approaches to BESS discharge operation. Peak shaving operation was found to be the most effective at reliably reducing the consumer POC maximum demand for both utility and consumer benefit. Section 3.5 investigated PV generation support and its impact on consumer load profiles. Two approaches to PV generation profile estimations were shown, however, software-based estimation was chosen due to its unequivocal practical accuracy and user-friendliness for any system design. This section also analysed increasing PV penetration levels within consumer profiles, demonstrating that energy cost savings can be achieved with the integration of irregular weather/seasonal dependent PV DG support. Section 3.6 combines the best approach to BESS maximum demand reduction (determined in Section 3.4) and PV DG support (determined in Section 3.5) to provide a conceptual power flow control algorithm for the overall DR system. The findings, ratings, and power flow control determined in this section are used in the Chapter 4 case study verification.

CHAPTER 4 CASE STUDY

4.1 CHAPTER OVERVIEW

The Chapter provides the case study network design and Quasi-Dynamic simulations in PowerFactory DIgSILENT. This includes maximised BESS and PV DG equipment ratings and the operation of the conceptual power flow control algorithms (as determined in the previous chapter) with the addition of reactive power considerations. Simulation outputs include fault levels, POC load profiles (with DR alterations), load factors, BESS parameters, operational voltage limits, BESS discharge/recharge power profiles, reactive power compensator power flows, and primary substation power transformer loading (from the development) per scenario.

In Section 4.2 the traditional method of network design is followed to calculate the authorised maximum demand and electrical equipment ratings of all connected consumers in the area by considering land zoning, area, density, ADMD, and internal coincident factors. Section 4.3 provides the external and internal network single line diagrams and defines the criteria for Quasi-Dynamic software simulations. In Section 4.4 the traditional network operation (without the integration of BESS or PV DG systems) is modelled to provide a comparative baseline prior to DR integration. Section 4.5 simulates the impact of BESS integration with power control to ensure that the reduced maximum demand remains within the defined limits should the support of PV DG become unavailable or reduced due to external factors, thereby determining the BESS equipment sizing. Section 4.6 simulates the impact of BESS integration with full PV DG support, governed by the full power flow control algorithm capability for DR system operation. Section 4.7 provides a comparative summary between the different scenarios to highlight key differences and future considerations for DR integration.

4.2 LAND USE AND BULK SUPPLY

To evaluate the performance and operation of a maximised DR integrated network, a typical mixed-use development is selected, situated in Ekurhuleni (Gauteng) at the corner of the R25 (K60) and the new R21 Expressway. The development areas and MV equipment are shown in Figure 4.1.

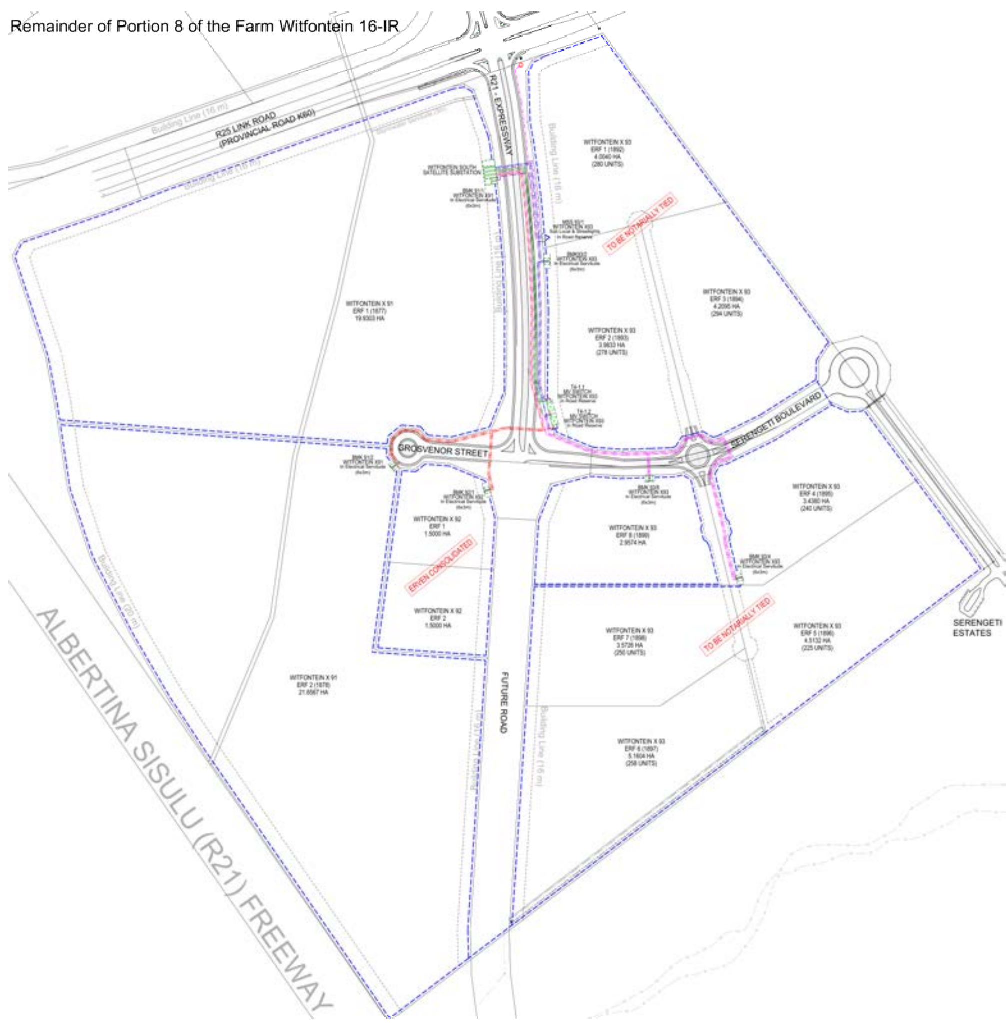


Figure 4.1. Case study development area land use and electrical infrastructure.

All consumer areas are supplied at 11 kV from the 20 MVA satellite WNS substation. The satellite substation is supplied by 4x 11 kV 300 mm^2 Al XLPE 3-core underground cables from the 88/11 kV 40 MVA firm capacity HBF primary substation (Figure 4.3).

Table 4.1 determines the enforced authorised capacity of each MV connection at the internal (consumer/end-user) to external (utility) network POC for electrical equipment sizing as per traditional supply authority demand calculations and Conditions of Establishment limitations (Section 2.5). Consolidated and Notarially Tied erven are noted.

Table 4.1 Authorised capacity and metering units of the development areas.

Ext.	Erf	Zoning	Area (ha)	Residential Density (Units/ha)	Number of Residential Units	GLA Density FAR/FSR	GLA (m^2)	ADMD: kVA/Unit or kVA/100m^2	Total (kVA)	Authorised Capacity (kVA)	Metering Unit (POC)
91	1	Industrial 1	19.9303	-	-	0.50	99 652	4.00	3 986	3 986	BMK 91/1
	2	Industrial 1	21.6567	-	-	0.50	108 284	4.00	4 331	4 331	BMK 91/2
92	1	Business 2	1.5000	-	-	0.35	5 250	8.00	420	840	BMK 92/1 (Consolidated)
	2	Business 2	1.5000	-	-	0.35	5 250	8.00	420		
93	1	Residential 3	4.0040	70	280	-	-	5.00	1 400	4 260	BMK 93/2 (Notarially Tied)
	2	Residential 3	3.9833	70	278	-	-	5.00	1 390		
	3	Residential 3	4.2095	70	294	-	-	5.00	1 470		
	4	Residential 3	3.4380	70	240	-	-	5.00	1 200	4 865	BMK 93/4 (Notarially Tied)
	5	Residential 3	4.5132	50	225	-	-	5.00	1 125		
	6	Residential 3	5.1604	50	258	-	-	5.00	1 290		
	7	Residential 3	3.5726	70	250	-	-	5.00	1 250		
	8	Business 2	2.9574	-	-	0.35	10 351	8.00	828	828	BMK 93/8
			76.4254		**1 825**		**228 786**		**19 110**	**19 110**	

Table 4.2 determines the internal network MSS sizing and LV connection sizes. An additional internal coincident factor (F_C) is allowed as shown in (4.1) and (4.2) as,

$$F_{C,Com} = 0.7596, \tag{4.1}$$

$$F_{C,Res} = 0.5059, \tag{4.2}$$

derived from supply authority maximum demand estimations compared to post-development smart-meter reading analysis from similar categorised developments

(Section 3.3). These coincident factors represent the findings of Section 2.5.3, and will prevent DR system oversizing in new developments where metering data is unavailable.

All pre-DR integrated distributed LV loads (excluding internal network distribution equipment) are assumed to have stable reactive power compensation installed as a significant reactive power component is expected with higher levels of active power injections (from PV and ES systems). This also isolates the DR reactive power impacts within integration results. Installing smaller and cheaper distributed power factor correction modules prepares the internal network for future DR integration by reducing the required POC compensation and strain on larger/expensive equipment needed to ensure system compliance with grid code requirements. This can be achieved by installing additional capacitor bank correction systems and/or utilising the reserve reactive power capacity (without the loss of active power output) from oversized inverters with phase shifting capability. The impacts of reactive power requirements are shown in Section 4.5 and Section 4.6 of the case study.

Table 4.2 Equipment sizing of the internal consumer networks.

Ext.	Erf	Zoning	Metering Unit	Total Load (kVA)	MSS Size (kVA)	Number of internal MSS	Internal F_C	Loading per MSS (kVA)	Loading per MSS (Incl. DF)	Maximum Demand (kVA)	Active Power Demand (kW)
91	1	Industrial 2	BMK 91/1	3 986	500	8	0.7596	378	76%	3 028	2 923
	2	Industrial 2	BMK 91/2	4 331	500	9	0.7596	366	73%	3 290	3 177
92	1	Business 2	BMK 92/1	840	500	2	0.7596	319	64%	638	616
	2	Business 2									
93	1	Residential 3	BMK 93/2	4 260	500	9	0.5059	239	48%	2 115	2 086
	2	Residential 3									
	3	Residential 3									
	4	Residential 3	BMK 93/4	4 865	500	10	0.5059	246	49%	2 461	2 382
	5	Residential 3									
	6	Residential 3									
	7	Residential 3									
	8	Business 2	BMK 93/8	828	500	2	0.7596	314	63%	629	608
				19 110		**40**				**12 201**	**11 792**

The "Maximum Demand (kVA)" is the representative MD_{Load} value, equal to MD_{NAC} without any DR integration. The "Active Power Demand (kW)" is the maximum active power of the load selected for DR equipment sizing (representing 100% of PV_{Pen} to rated inverter outputs). All other development area loads not affected by the sizing of DR equipment are not explicitly shown on the diagrams and are excluded in the simulation comparisons (such as contribution to primary transformer loading) as they remain unchanged. These loads include all other local substation connections, streetlights, other MV or LV consumers, and a second satellite substation to the North (located to the north of the area shown in Figure 4.1).

4.3 NETWORK SIMULATION

Power flow simulations were conducted using the Quasi-Dynamic functionality of the PowerFactory DIgSILENT software. System studies require network operation simulated under worst-case scenarios. Substation operation can be defined as double-feed (with an open bus-coupler, each bus-section energised through the section incomer/s) or single-feed (one bus-section energised through a closed bus-coupler) while avoiding long term primary transformer parallel operation. The normal operation of the external (utility) network is depicted in Figure 4.2 with primary (HBF) and satellite (WNS) substations operating in a high redundant double-feed operation. Verified from pre-study simulations it can be shown that for this network:

- HBF and WNS substations in single-feed operation (with two incomers energised on the same WNS bus-section) will result in the worst-case operational short-circuit levels (apart from paralleled HBF transformers during short-time over-switching).
- HBF and WNS substations in double-feed operation (with two incomers energised on the same WNS bus-section) will result in the highest daily voltage profile (U_{max}).
- HBF and WNS substations in single-feed operation (with one incomer energised on a WNS bus-section) will result in the lowest daily voltage profile (U_{min}).
- HBF in single-feed operation will result in the highest primary substation power transformer loading.

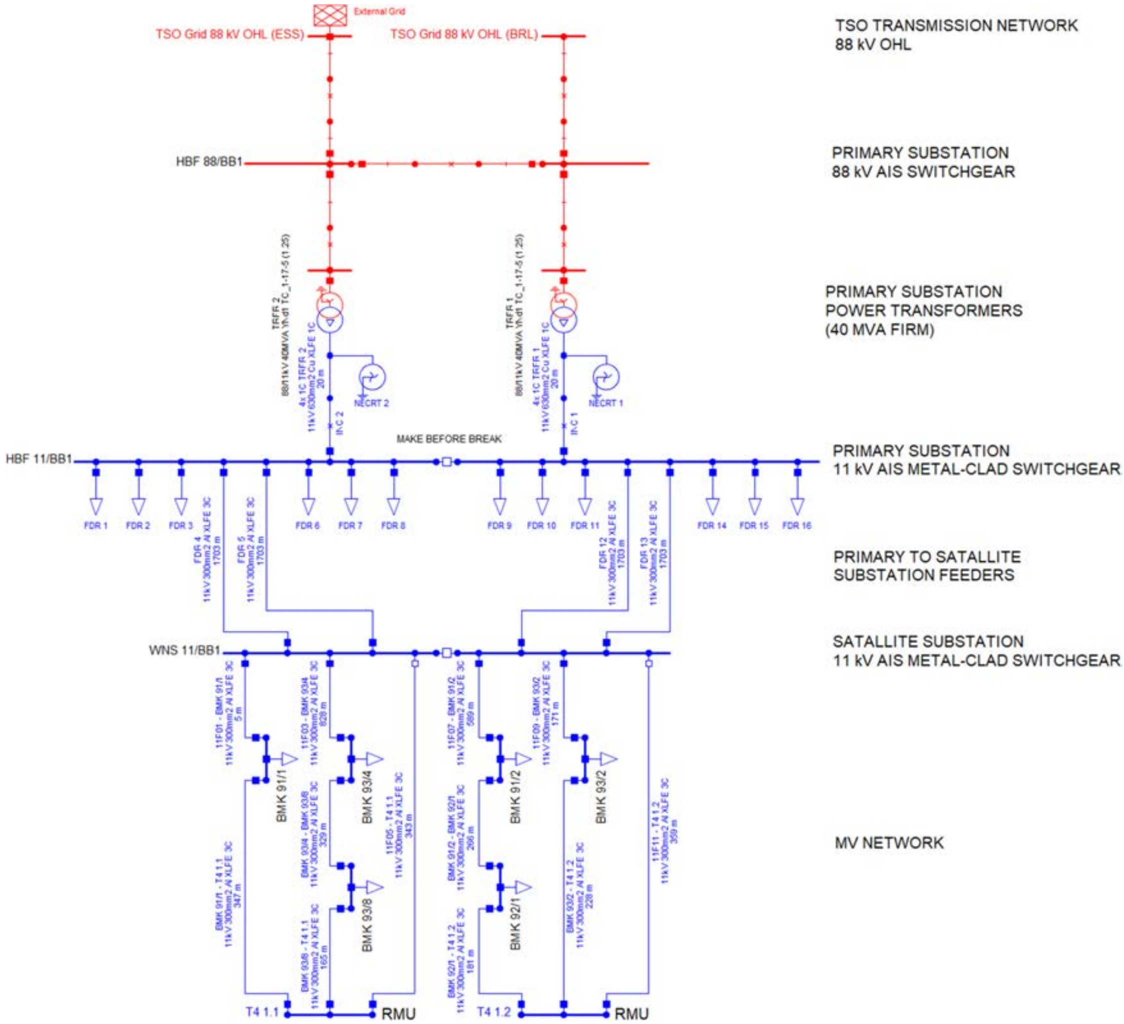


Figure 4.2. External (Utility) network PowerFactory configuration in double-feed.

The internal (DR consumer/end-user) load sharing network configurations depicted in Figure 4.3 indicate the distributed LV loads, LV DG PV systems, local MSSs (MV/LV), and storage systems (BESSs including MV transformers) connected to the MV BMK (POC). Internal MV networks/rings, and other RMU equipment, are not shown in detail. Individual internal network DR equipment is assumed to be controlled by one common PPC, equivalent in DIgSILENT as the Station Controller element. Load sharing distributed LV busses are connected to separate MV/LV distribution transformers each with its own LV load and PV DG system similar to Figure 1.1b.

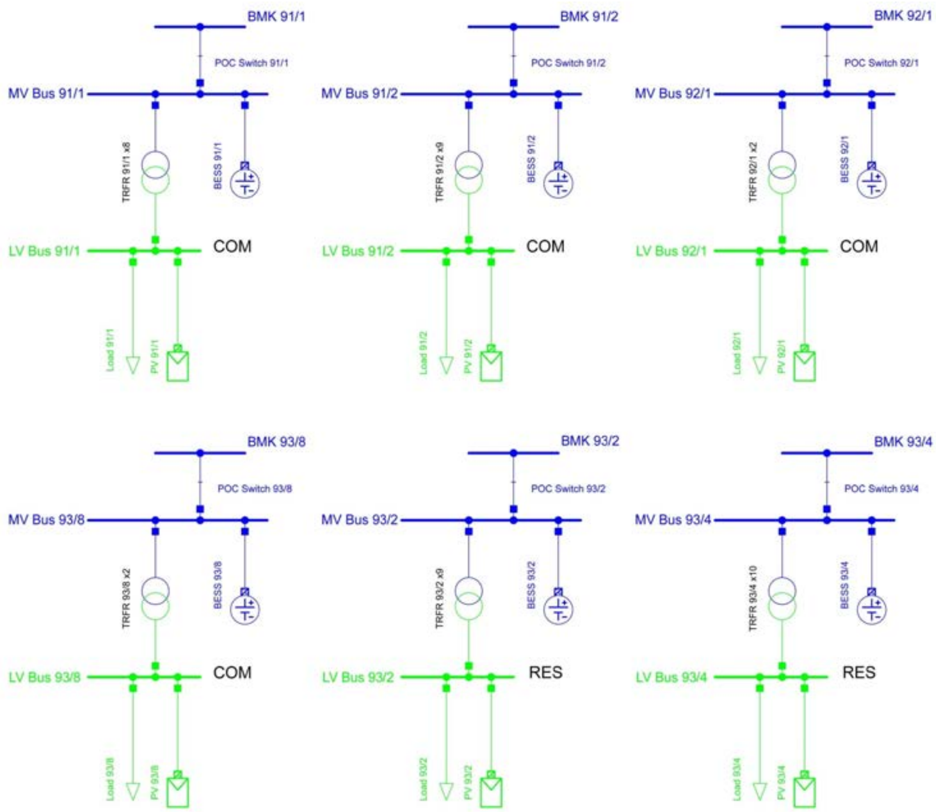


Figure 4.3. Internal (DR end-user) network PowerFactory configuration (Simplified).

Load profiles with a reading resolution of 5-minutes are scaled to Figure 3.2a (Commercial/Non-residential) and Figure 3.2b (Residential) with internal network parameters calculated in Table 4.2. Internal MSSs are included in the simulations with typical parameters as per OEM datasheets. Calculations include all transformer active power losses and reactive power requirements [113], [114].

Short-circuit analysis will be simulated to IEC 60909 considering that PV DG and BESS OEM data are unknown at this initial stage of the study. Symmetrical short-circuit contribution is selected to a conservative 1.2 pu of rated inverter outputs (current-source) assuming possible inverter oversizing for initial load reactive power support with phase shifting capability. Since the internal network cabling (and associated impedances) are not included in the model, distributed PV systems fault current contributions at the MV busses are expected to be lower in practice. Results include I_{kss} initial symmetrical short-circuit current (RMS) for MV switchgear grading (interrupting and breaking capacity), and i_p peak short-circuit current (instantaneous value) relevant to the overall system design including conductors, protection devices, and coordination. Operational POC voltage profiles must remain within grid connection guidelines [34], [35],

$$0.90 < U < 1.08. \tag{4.3}$$

The highest non-residential (BMK 91/2) and residential (BMK 93/4) POC load demands are selected for all simulation profile figures as all similar zoned connections will behave comparably. Specific magnitudes of all development areas are shown in the output tables.

4.4 TRADITIONAL NETWORK SIMULATIONS

Traditional network parameters are simulated to provide the initial base case comparative scenario results to evaluate the impacts of BESS-only (no PV generation) and BESS integration with full PV DG supported systems.

Traditional network short-circuit simulation results are shown in Table 4.3.

Table 4.3 Traditional network short-circuit calculation results.

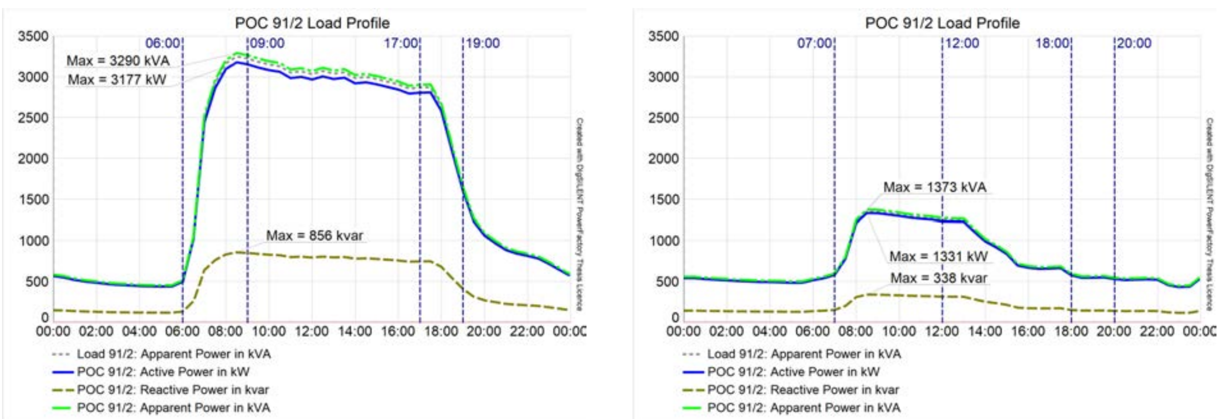
	MV Internal Network						MV External Network		Unit
Bus	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**WNS 11**	**HBF 11**	
I_{kss}	18.3	16.5	16.5	17.5	16.1	16.4	18.4	24.1	kA
i_p	36.5	30.7	30.7	33.8	29.7	30.5	36.6	67.8	kA

Internal network MV switchgear should be graded to a minimum short-time withstand current of 25 kA for 3 seconds (with a peak rating of 63 kA), considering that the maximum calculated three-phase fault within the internal network is 18.3 kA (36.5 kA peak).

External network MV switchgear can be graded similarly, except for the primary substation switchgear (Bus HBF) which should be graded to a minimum short-time withstand current of 31.5 kA for 3 seconds (with a peak rating of 80 kA). This is due to the 24.1 kA (67.8 kA peak) maximum three-phase fault calculated at the bus and that additional fault level contributions are being anticipated from downstream network integrated DRs.

4.4.1 High demand (Traditional)

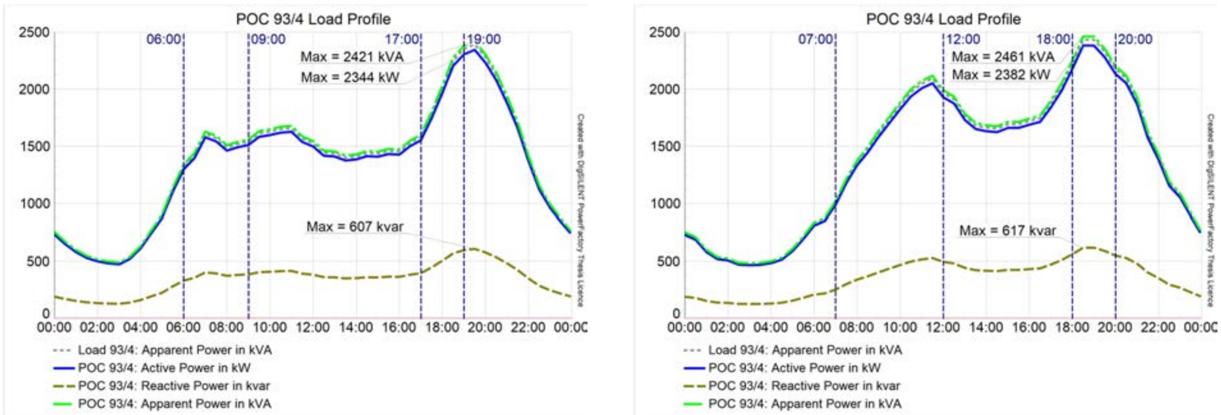
The simulated traditional (base case) load profiles are shown in Figure 4.4 and Figure 4.5.



(a) (b)

Figure 4.4. High demand non-residential base case POC load profiles.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 4.5. High demand residential base case POC load profiles.

(a) Weekday demand. (b) Weekend demand.

Results are summarised in Table 4.4 (Weekday) and Table 4.5 (Weekend) to confirm Chapter 3 first principle estimations.

Table 4.4 High demand, base case weekday calculation results.

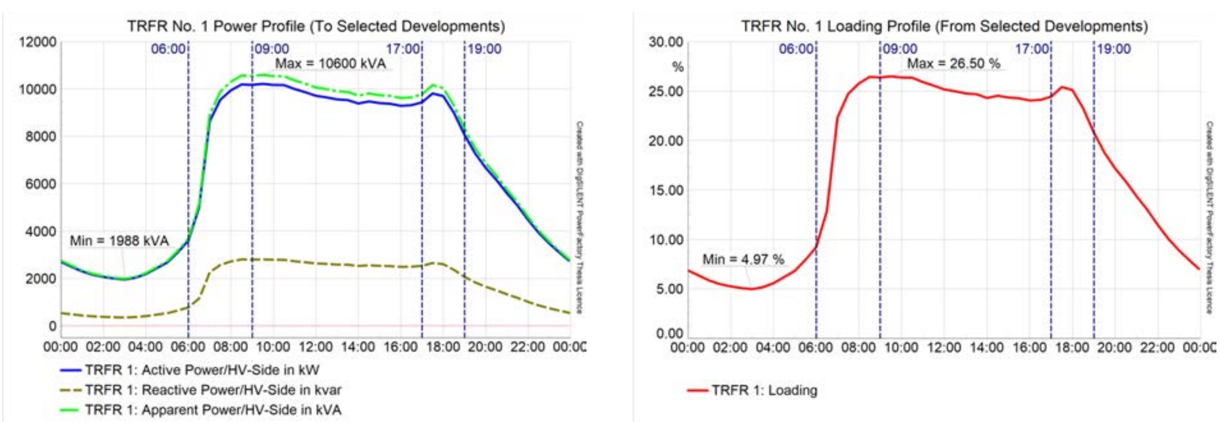
BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
MD_{POC}	3 028	3 290	638	2 120	2 421	629	kVA
$MD_{POC,P}$	2 923	3 177	616	2 053	2 344	608	kW
$MD_{POC,Q}$	791	856	163	530	607	161	kvar
LF	57%	57%	57%	57%	57%	57%	
U_{Min}	0.9711	0.9694	0.9697	0.9704	0.9700	0.9703	pu
U_{Max}	0.9986	0.9984	0.9984	0.9985	0.9983	0.9984	pu

Table 4.5 High demand, base case weekend calculation results.

BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
MD_{POC}	1 263	1 373	267	2 155	2 461	263	kVA
$MD_{POC,P}$	1 224	1 331	258	2 086	2 382	255	kW
$MD_{POC,Q}$	311	338	66	540	617	65	kvar
LF	56%	56%	56%	58%	58%	56%	
U_{Min}	0.9815	0.9808	0.9808	0.9811	0.9804	0.9808	pu
U_{Max}	0.9985	0.9983	0.9983	0.9984	0.9983	0.9983	pu

The POC power factors and voltage magnitudes remain within acceptable limits for all connected MV loads.

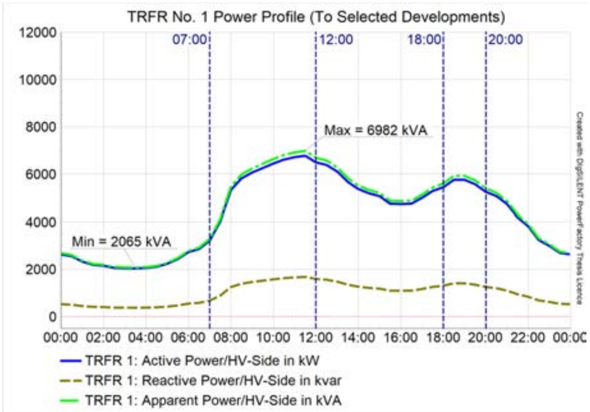
Traditional design high demand primary transformer single-feed loading is shown in Figure 4.6 (weekday) and Figure 4.7 (weekend).



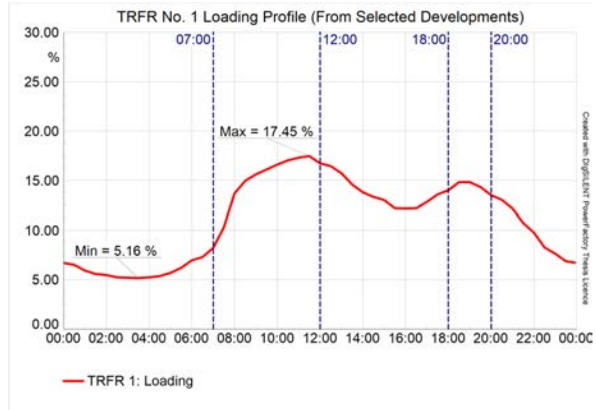
(a) (b)

Figure 4.6. High demand weekday primary substation transformer loading.

(a) Active, Reactive, and Apparent Power. (b) Loading percentage.



(a)



(b)

Figure 4.7. High demand weekend primary substation transformer loading.

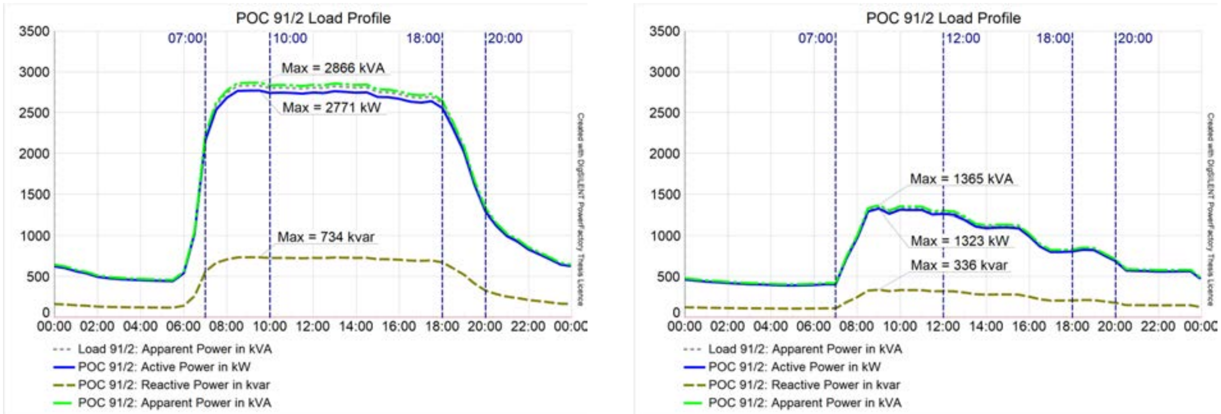
(a) Active, Reactive, and Apparent Power. (b) Loading percentage.

High demand weekday results indicate allocated loading ranging from 4.97% (1 988 kVA) to a maximum of 26.50% (10 600 kVA), with a development load factor of 65.39%. High demand weekend results indicate allocated loading ranging from 5.16% (2 065 kVA) to a maximum of 17.45% (6 982 kVA), with a development load factor of 63.97%.

High demand traditional network results indicate a weekend development maximum demand at the primary substation in the order of 66% when compared to the yearly maximum demand of the traditional network base case approach.

4.4.2 Low demand (Traditional)

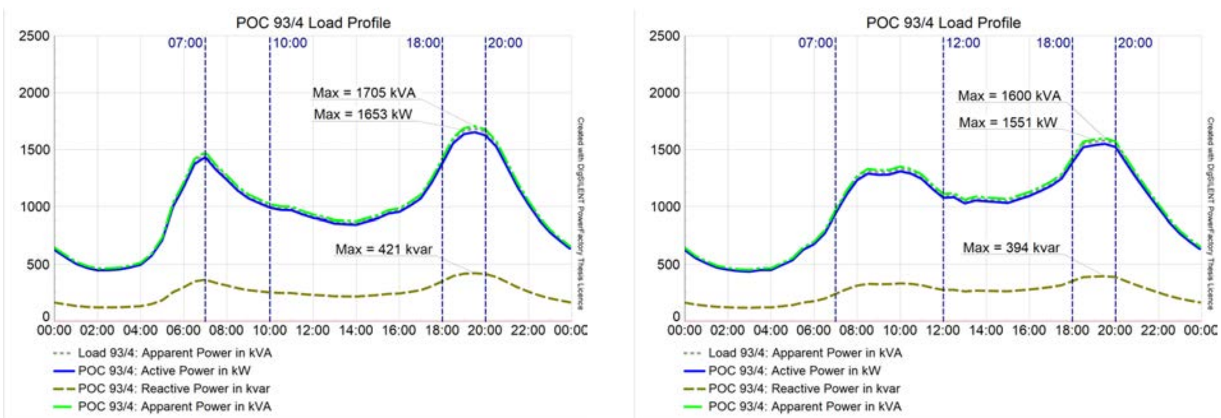
The simulated traditional (base case) load profiles are shown in Figure 4.8 and Figure 4.9.



(a) (b)

Figure 4.8. Low demand non-residential base case POC load profiles.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 4.9. Low demand residential base case POC load profiles.

(a) Weekday demand. (b) Weekend demand.

Results are summarised in Table 4.6 (Weekday) and Table 4.10 (Weekend) to confirm Chapter 3 first principle estimations.

Table 4.6 Low demand, base case weekday calculation results.

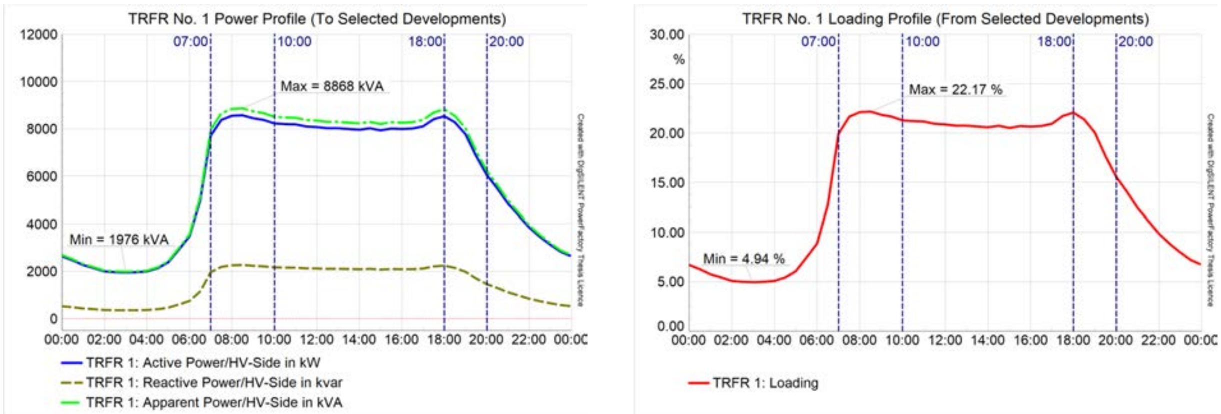
BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
$\boldsymbol{MD_{POC}}$	2 638	2 866	556	1 493	1 705	548	kVA
$\boldsymbol{MD_{POC,P}}$	2 549	2 771	538	1 447	1 653	530	kW
$\boldsymbol{MD_{POC,Q}}$	678	734	141	368	421	139	kvar
LF	62%	62%	62%	59%	59%	62%	
$\boldsymbol{U_{Min}}$	0.9761	0.9746	0.9749	0.9756	0.9753	0.9755	pu
$\boldsymbol{U_{Max}}$	0.9986	0.9984	0.9984	0.9985	0.9983	0.9984	pu

Table 4.7 Low demand, base case weekend calculation results.

BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
$\boldsymbol{MD_{POC}}$	1 256	1 365	265	1 401	1 600	261	kVA
$\boldsymbol{MD_{POC,P}}$	1 218	1 323	257	1 358	1 551	253	kW
$\boldsymbol{MD_{POC,Q}}$	309	336	65	345	394	64	kvar
LF	59%	59%	59%	63%	63%	59%	
$\boldsymbol{U_{Min}}$	0.9852	0.9845	0.9846	0.9849	0.9845	0.9847	pu
$\boldsymbol{U_{Max}}$	0.9987	0.9985	0.9986	0.9986	0.9985	0.9986	pu

The POC power factors and voltage magnitudes remain within acceptable limits for all connected MV loads.

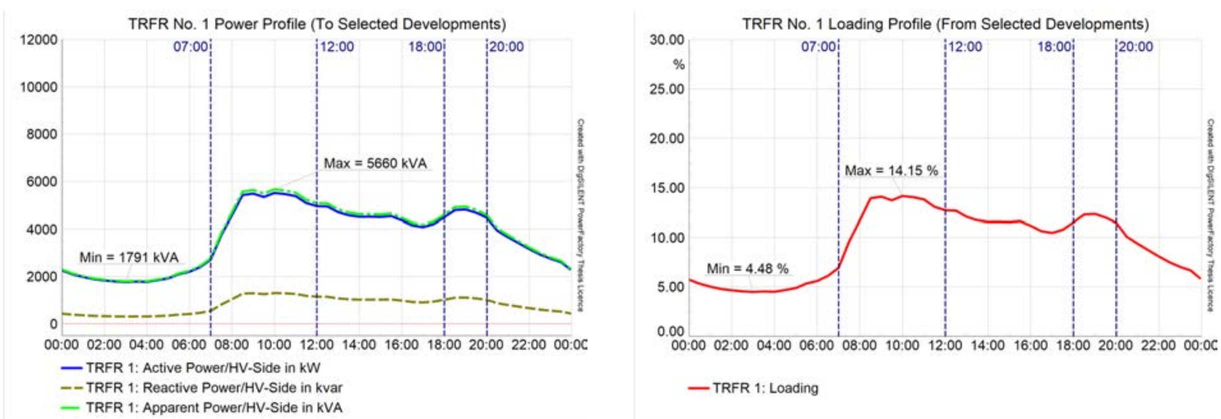
Traditional design low demand primary transformer single-feed loading is shown in Figure 4.10 (weekday) and Figure 4.11 (weekend).



(a) (b)

Figure 4.10. Low demand weekday primary substation transformer loading.

(a) Active, Reactive, and Apparent Power. (b) Loading percentage.



(a) (b)

Figure 4.11. Low demand weekend primary substation transformer loading.

(a) Active, Reactive, and Apparent Power. (b) Loading percentage.

Low demand weekday results indicate allocated loading ranging from 4.94% (1 976 kVA) to a maximum of 22.17% (8 868 kVA), with a development load factor of 67.78%. Low demand weekend results indicate allocated loading ranging from 4.48% (1 791 kVA) to a maximum of 14.15% (5 660 kVA), with a development load factor of 66.30%.

Low demand traditional network results indicate a development maximum demand in the order of 84% (weekday) to 53% (weekend) at the primary substation when compared to the yearly maximum demand of the traditional network base case approach.

4.5 BESS INTEGRATION WITHOUT PV GENERATION SUPPORT

BESS integration with peak shaving and control is simulated to assess the impacts on network parameters in scenarios with poor or no PV energy generation available. BESSs are rated to maximum peak shaving capability to set an upper integration limit. In practice, BESS ratings are expected to be lower when considering feasibility study recommendations (Section 3.4.5) that will result in smaller ES systems, a reduced peak shaving demand value, and a decreased load factor. Additional reactive power compensation equipment is connected for reactive power control (to equipment reactive power capability curves) to ensure a power factor of 0.975 lagging (PF_{DR}) in compliance with the South African grid code for Category B and C BESS installations [35]. BESS discharge is not required during non-residential or low demand residential weekends since the maximum demands are already lower than the defined BESS peak shaving setpoint value (Section 3.4.4). All energy consumed during these times is billed to either standard or off-peak TOU tariffs.

Following the simulations in Section 3.4.4, MV BESSs are rated to maximum peak shaving capability with ratings and control parameters defined in Table 3.26 (Non-residential) and Table 3.31 (Residential). Internal development BESS equipment ratings are provided in Table 4.8.

Table 4.8 BESS equipment ratings (To absolute maximums).

POC	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
$\boldsymbol{ES_{PCS}}$	2 016	2 191	425	752	859	419	kW
$\boldsymbol{ES_{Cap}}$	10 081	10 956	2 126	3 761	4 293	2 096	kWh

BESS-only network short-circuit simulation results are shown in Table 4.9.

Table 4.9 BESS-only short-circuit calculation results.

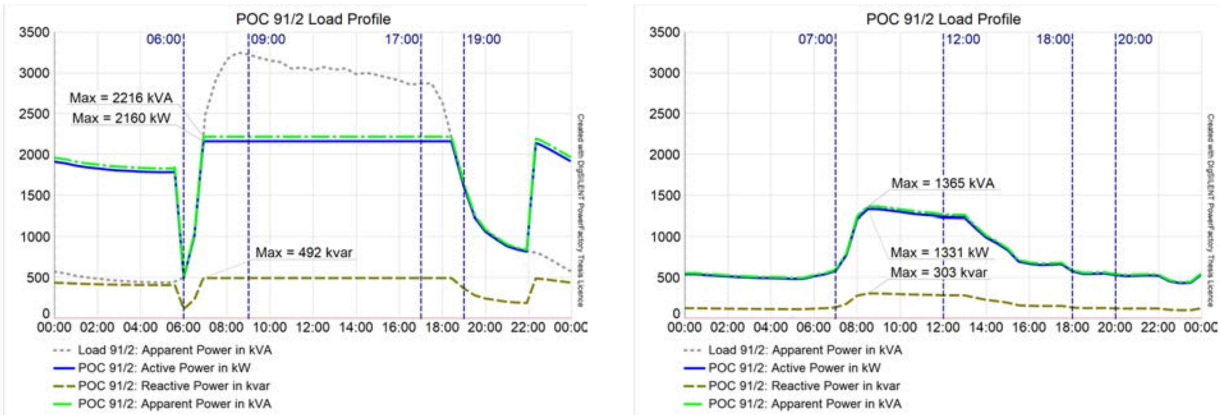
	MV Internal Network						MV External Network		Unit
Bus	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**WNS 11**	**HBF 11**	
I_{kss}	18.8	16.9	16.9	17.9	16.5	16.8	18.8	24.6	kA
i_p	37.1	31.2	31.2	34.3	30.2	31.1	37.2	68.4	kA

The internal network MV switchgear, with a minimum short-time withstand current rating of 25 kA for 3 seconds (63 kA peak), remains sufficiently graded as the maximum three-phase fault calculated is 18.8 kA (37.1 kA peak). Results indicate a 2.29% to 2.73% increase in the minimum short-time withstand current requirement when compared to traditional network design.

The external network MV switchgear, with a minimum short-time withstand current rating of 25 kA for 3 seconds (63 kA peak) and 31.5 kA for 3 seconds (80 kA peak) remains sufficiently graded as the maximum three-phase fault calculated is 18.8 kA (37.2 kA peak) for the satellite and 24.6 kA (68.4 kA peak) for the primary substation switchgear, respectively. Results indicate a 2.07% to 2.17% increase in the minimum short-time withstand current requirement when compared to traditional network design.

4.5.1 High demand (BESS active, no PV DG)

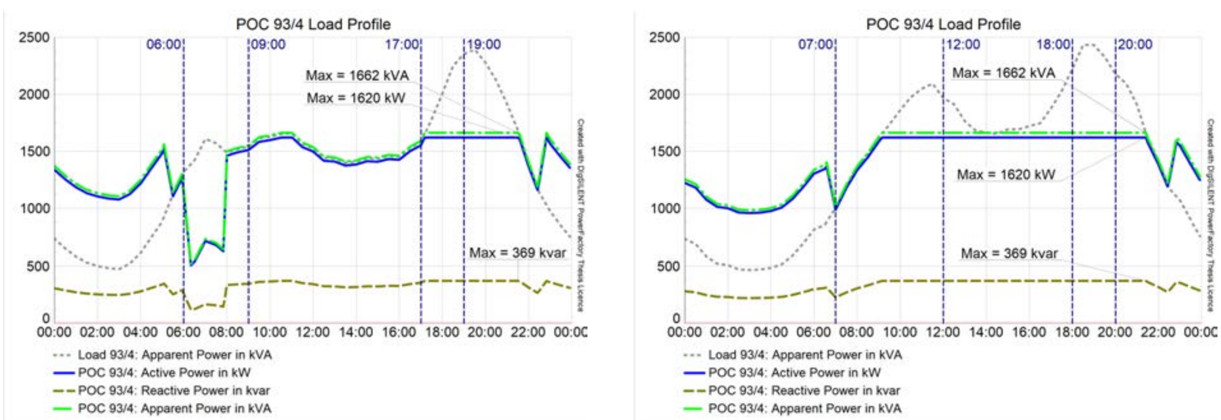
The simulated load profiles that include BESS operation are shown in Figure 4.12 and Figure 4.13.



(a) (b)

Figure 4.12. High demand non-residential BESS-only POC load profiles.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 4.13. High demand residential BESS-only POC load profiles.

(a) Weekday demand. (b) Weekend demand.

Results are summarised in Table 4.10 (Weekday) and Table 4.11 (Weekend) to confirm Chapter 3 first principle estimations.

Table 4.10 High demand, BESS-only weekday calculation results.

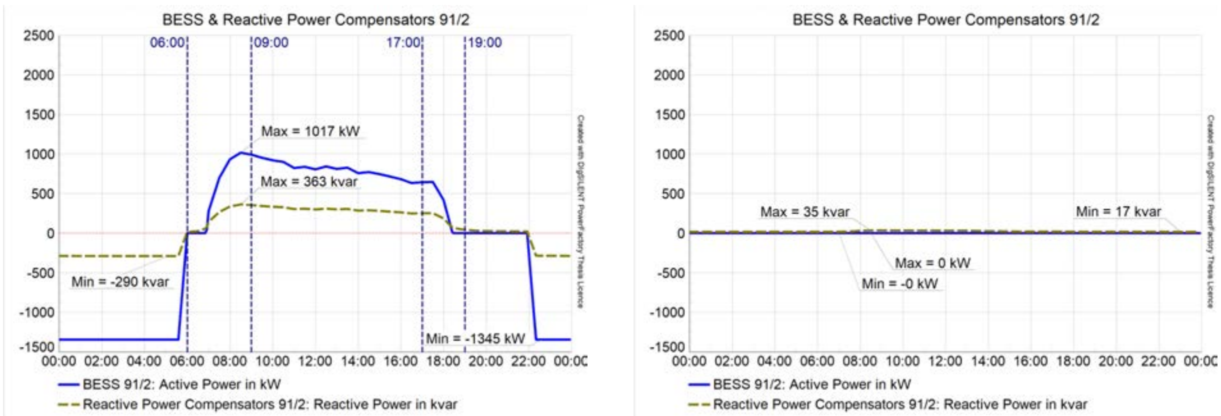
BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
MD_{POC}	2 039	2 216	430	1 455	1 662	424	kVA
$MD_{POC,P}$	1 988	2 160	419	1 419	1 620	413	kW
$MD_{POC,Q}$	453	492	96	323	369	94	kvar
LF	86%	86%	86%	85%	85%	86%	
ES_{Util}	100%	100%	100%	100%	100%	100%	
ES_S	0	0	0	0	0	0	kWh
ES_{CRR}	12%	12%	12%	14%	14%	12%	per 5 min
U_{Min}	0.9786	0.9774	0.9776	0.9781	0.9776	0.9779	pu
U_{Max}	0.9980	0.9975	0.9976	0.9978	0.9976	0.9977	pu

Table 4.11 High demand, BESS-only weekend calculation results.

BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
MD_{POC}	1 256	1 365	265	1 455	1 662	261	kVA
$MD_{POC,P}$	1 224	1 331	258	1 419	1 620	255	kW
$MD_{POC,Q}$	279	303	59	323	369	58	kvar
LF	56%	56%	56%	87%	87%	56%	
ES_{Util}	0%	0%	0%	100%	100%	0%	
ES_S	8 065	8 765	1 701	0	0	1 677	kWh
ES_{CRR}	0%	0%	0%	12%	12%	0%	per 5 min
U_{Min}	0.9840	0.9833	0.9834	0.9836	0.9831	0.9834	pu
U_{Max}	0.9978	0.9977	0.9977	0.9978	0.9973	0.9975	pu

The POC power factors and voltage magnitudes remain within acceptable limits for all connected MV loads.

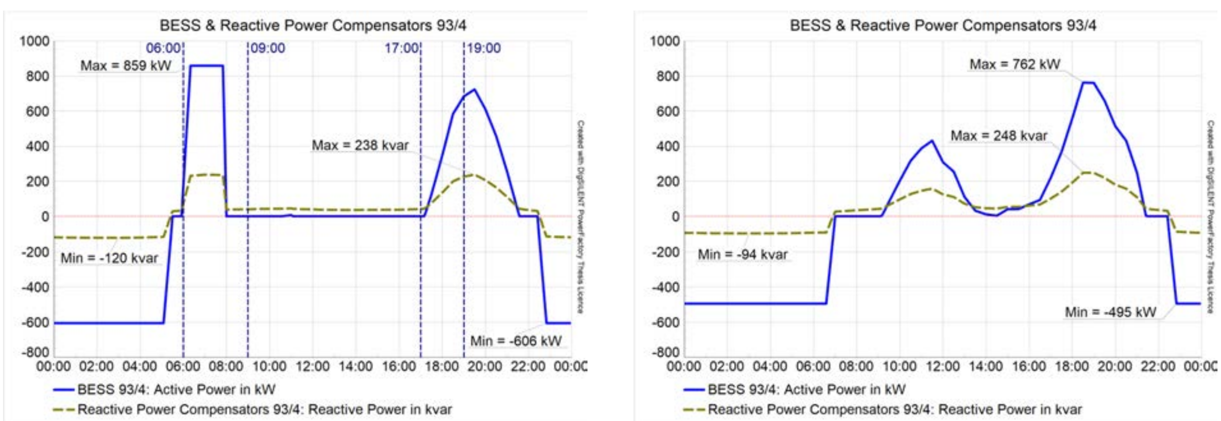
The power profiles of the BESS and reactive power compensator equipment are shown in Figure 4.14 and Figure 4.15, with the reactive power component (output or absorption) adjusted to maintain a power factor of 0.975 lagging (PF_{DR}) to ensure reactive power grid code compliance at the POC. BESS surplus discharge, as calculated in (3.60), is evident in residential weekday profiles.



(a) (b)

Figure 4.14. High demand non-residential BESS-only BESS and Compensator power.

(a) Weekday demand. (b) Weekend demand.

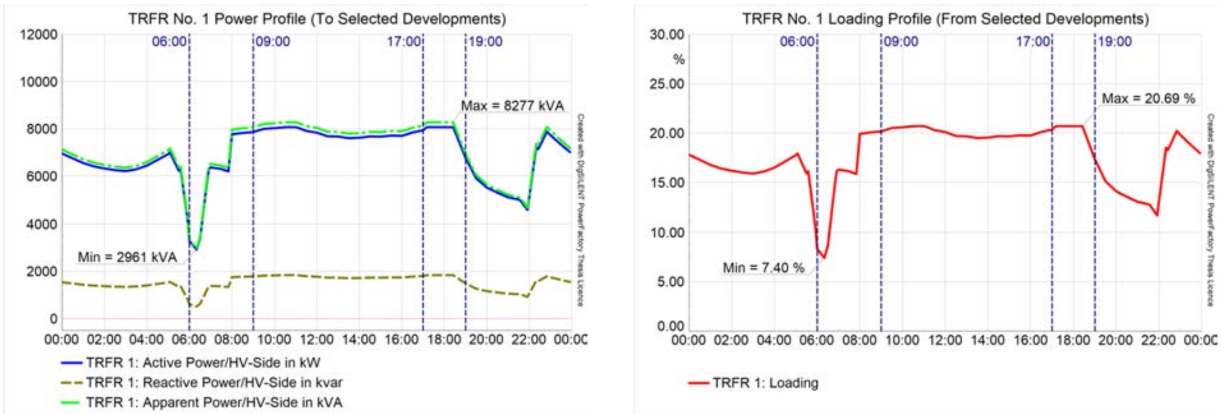


(a) (b)

Figure 4.15. High demand residential BESS-only BESS and Compensator power.

(a) Weekday demand. (b) Weekend demand.

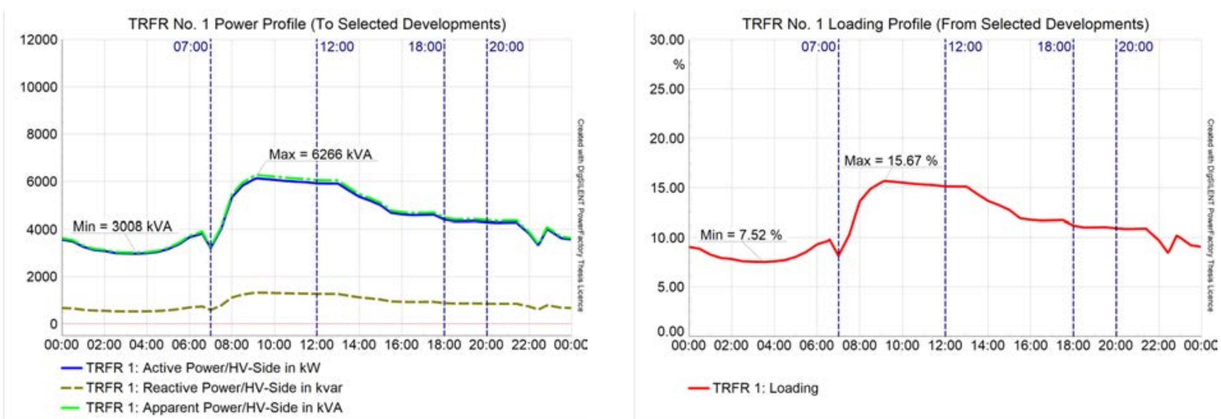
The impact of BESS operation (without PV DG) on the high demand primary transformer single-feed loading are shown in Figure 4.16 (weekday) and Figure 4.17 (weekend).



(a) (b)

Figure 4.16. High demand weekday primary substation transformer loading.

(a) Active, Reactive, and Apparent Power. (b) Loading percentage.



(a) (b)

Figure 4.17. High demand weekend primary substation transformer loading.

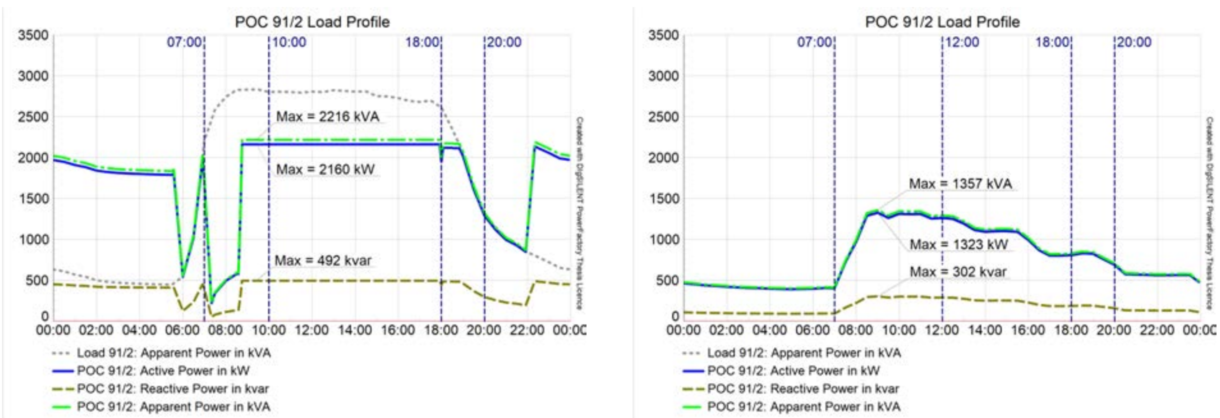
(a) Active, Reactive, and Apparent Power. (b) Loading percentage.

High demand weekday results indicate allocated loading ranging from 7.40% (2 961 kVA) to a maximum of 20.69% (8 277 kVA), with a development load factor of 85.41%. High demand weekend results indicate allocated loading ranging from 7.52% (3 008 kVA) to a maximum of 15.67% (6 266 kVA), with a development load factor of 71.60%.

High demand BESS integration results (without PV generation support), indicate a development maximum demand in the order of 78% (weekday) to 59% (weekend) at the primary substation when compared to the yearly maximum demand of the traditional network base case approach.

4.5.2 Low demand (BESS active, no PV DG)

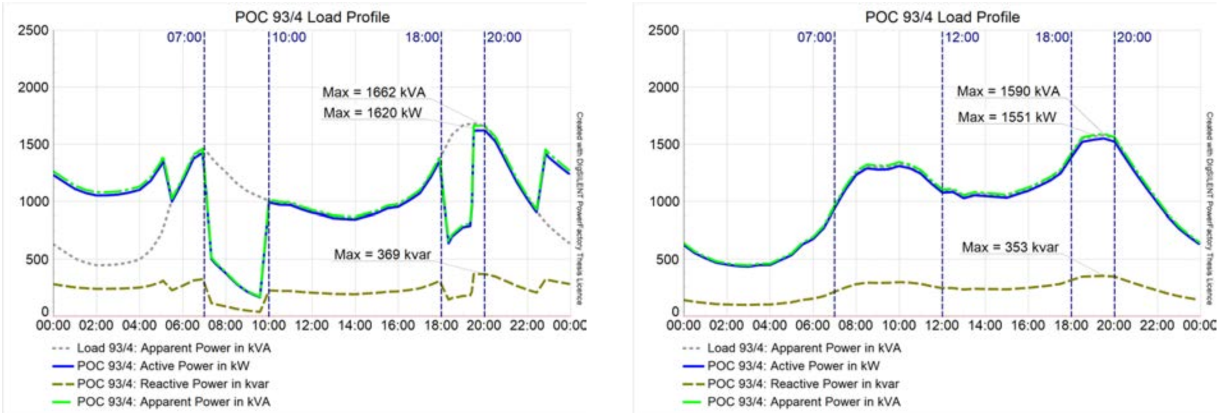
The simulated load profiles that include BESS operation are shown in Figure 4.18 and Figure 4.19.



(a) (b)

Figure 4.18. Low demand non-residential BESS-only POC load profiles.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 4.19. Low demand residential BESS-only POC load profiles.

(a) Weekday demand. (b) Weekend demand.

Results are summarised in Table 4.12 (Weekday) and Table 4.13 (Weekend) to confirm Chapter 3 first principle estimations.

Table 4.12 Low demand, BESS-only weekday calculation results.

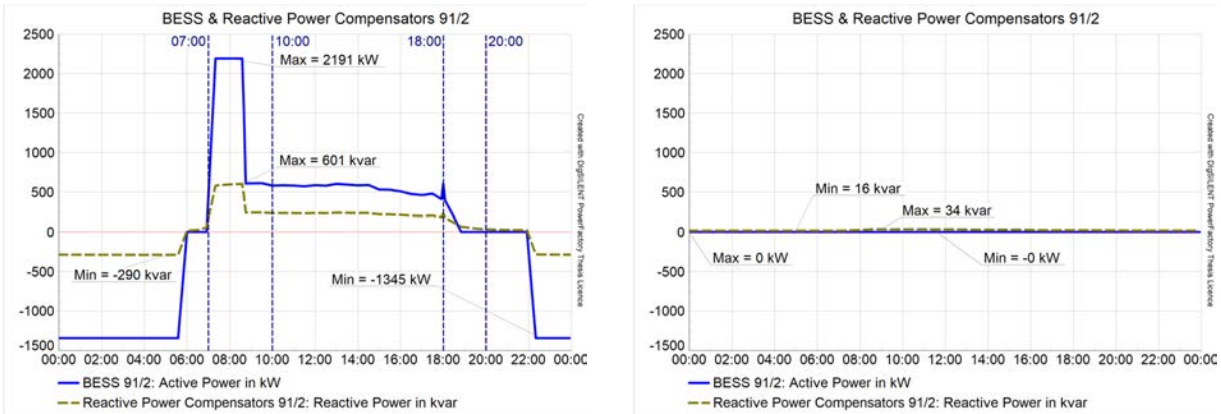
BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
MD_{POC}	2 039	2 216	430	1 455	1 662	424	kVA
$MD_{POC,P}$	1 988	2 160	419	1 419	1 620	413	kW
$MD_{POC,Q}$	453	492	96	323	369	94	kvar
LF	82%	82%	82%	62%	62%	82%	
ES_{Util}	100%	100%	100%	100%	100%	100%	
ES_S	0	0	0	0	0	0	kWh
ES_{CRR}	12%	12%	12%	14%	14%	12%	per 5 min
U_{Min}	0.9800	0.9789	0.9790	0.9796	0.9792	0.9794	pu
U_{Max}	0.9991	0.9990	0.9990	0.9990	0.9988	0.9989	pu

Table 4.13 Low demand, BESS-only weekend calculation results.

BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
MD_{POC}	1 249	1 357	264	1 393	1 590	260	kVA
$MD_{POC,P}$	1 218	1 323	257	1 358	1 551	253	kW
$MD_{POC,Q}$	277	302	59	310	353	58	kvar
LF	59%	59%	59%	63%	63%	59%	
ES_{Util}	0%	0%	0%	0%	0%	0%	
ES_S	8 065	8 765	1 701	3 008	3 434	1 677	kWh
ES_{CRR}	0%	0%	0%	0%	0%	0%	per 5 min
U_{Min}	0.9857	0.9850	0.9851	0.9854	0.9850	0.9852	pu
U_{Max}	0.9988	0.9986	0.9987	0.9988	0.9986	0.9987	pu

The POC power factors and voltage magnitudes remain within acceptable limits for all connected MV loads.

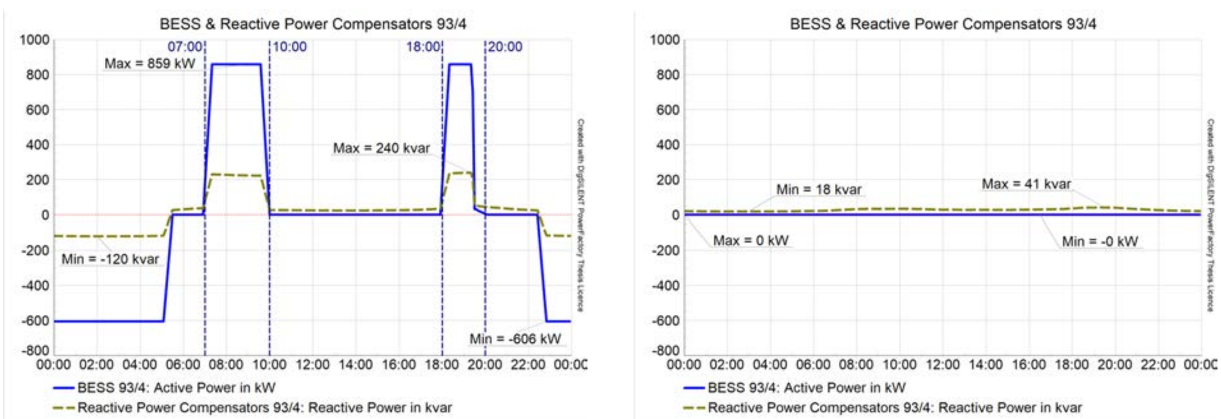
The power profiles of the BESS and reactive power compensator equipment are shown in Figure 4.20 and Figure 4.21, with the reactive power component (output or absorption) adjusted to maintain a power factor of 0.975 lagging (PF_{DR}) to ensure reactive power grid code compliance at the POC. BESS surplus discharge, as calculated in (3.60), is evident in all weekday profiles.



(a) (b)

Figure 4.20. Low demand non-residential BESS-only BESS and Compensator power.

(a) Weekday demand. (b) Weekend demand.

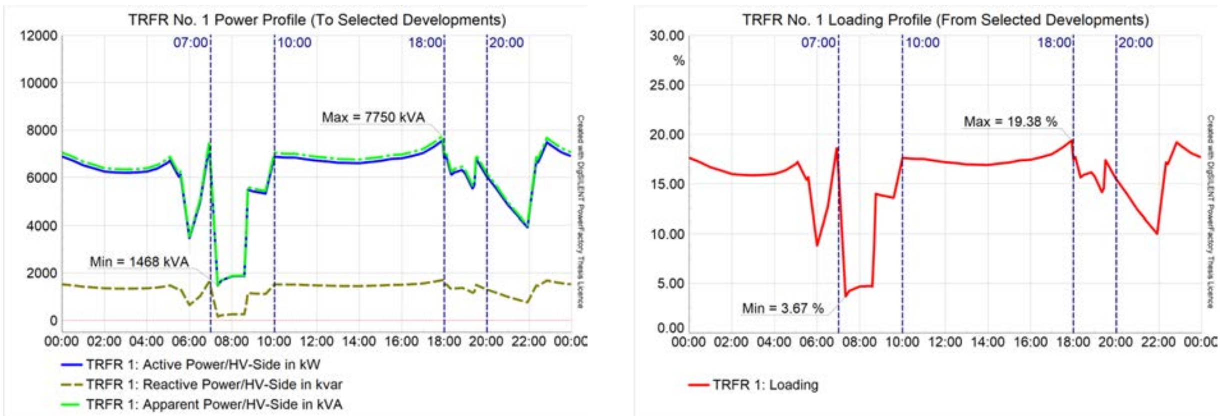


(a) (b)

Figure 4.21. Low demand residential BESS-only BESS and Compensator power.

(a) Weekday demand. (b) Weekend demand.

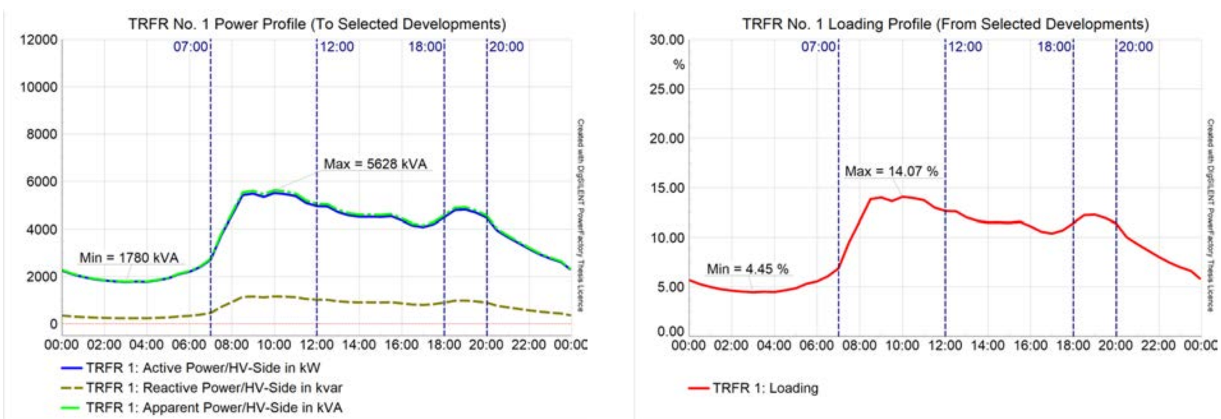
The impact of BESS operation (without PV DG) on the low demand primary transformer single-feed loading are shown in Figure 4.22 (weekday) and Figure 4.23 (weekend).



(a) (b)

Figure 4.22. Low demand weekday primary substation transformer loading.

(a) Active, Reactive, and Apparent Power. (b) Loading percentage.



(a) (b)

Figure 4.23. Low demand weekend primary substation transformer loading.

(a) Active, Reactive, and Apparent Power. (b) Loading percentage.

Low demand weekday results indicate allocated loading ranging from 3.67% (1 468 kVA) to a maximum of 19.38% (7 750 kVA), with a development load factor of 79.54%. Low demand weekend results indicate allocated loading ranging from 4.45% (1 780 kVA) to a maximum of 14.07% (5 628 kVA), with a development load factor of 66.30%.

Low demand BESS integration results (without PV generation support), indicate a development maximum demand in the order of 73% (weekday) to 53% (weekend) at the primary substation when compared to the yearly maximum demand of the traditional network base case approach.

4.6 BESS INTEGRATION WITH PV GENERATION SUPPORT

Peak shaving BESS integration is simulated with full output PV DG to provide operational support as defined in Section 3.6. Simulation outputs will confirm the operation of the defined power management system and determine the impact on network parameters should there be maximum DR load penetration through BESS operation and PV DG. External grid feed-in is disabled at the customer POC through power control as a precautionary measure considering that all local loads are implementing high levels of PV_{Pen}. This is a necessary requirement to prevent negative power flows at the primary substation, especially during high PV generation periods with low shared network demands.

BESS equipment ratings remain unchanged as shown in Table 4.8. LV PV energy generation is simulated to absolute maximums with penetration levels set to 104% of the non-residential load demand peaks and to 51% of the residential load demand peaks (Section 3.6.2). Internal development PV DG equipment ratings are provided in Table 4.14.

Table 4.14 PV DG equipment ratings (To absolute maximums).

POC	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
$\boldsymbol{DG_{PV,pk}}$	3 040	3 304	641	1 064	1 215	632	kWp

Full DR integrated network short-circuit simulation results are shown in Table 4.15.

Table 4.15 DR short-circuit calculation results.

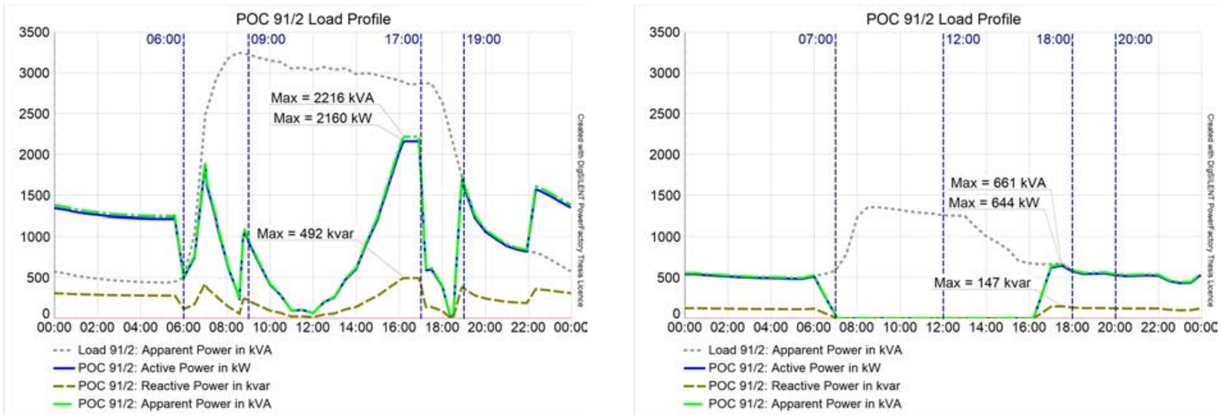
	MV Internal Network						MV External Network		Unit
Bus	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**WNS 11**	**HBF 11**	
I_{kss}	19.4	17.5	17.5	18.5	17.1	17.4	19.4	25.2	kA
i_p	37.9	32.0	32.1	35.2	31.0	31.9	38.0	69.2	kA

The internal network MV switchgear, with a minimum short-time withstand current rating of 25 kA for 3 seconds (63 kA peak), remains sufficiently graded as the maximum three-phase fault calculated is 19.4 kA (37.9 kA peak). Results indicate a 5.71% to 6.21% increase in the minimum short-time withstand current requirement when compared to traditional network design.

The external network MV switchgear, with a minimum short-time withstand current rating of 25 kA for 3 seconds (63 kA peak) and 31.5 kA for 3 seconds (80 kA peak) remains sufficiently graded as the maximum three-phase fault calculated is 19.4 kA (38.0 kA peak) for the satellite and 25.2 kA (69.2 kA peak) for the primary substation switchgear, respectively. Results indicate a 4.56% to 5.43% increase in the minimum short-time withstand current requirement when compared to traditional network design, and that 25 kA rated switchgear at the primary substation (bus HBF) would have been marginally too small due to downstream network DR fault level contributions.

4.6.1 High demand (BESS and PV DG active)

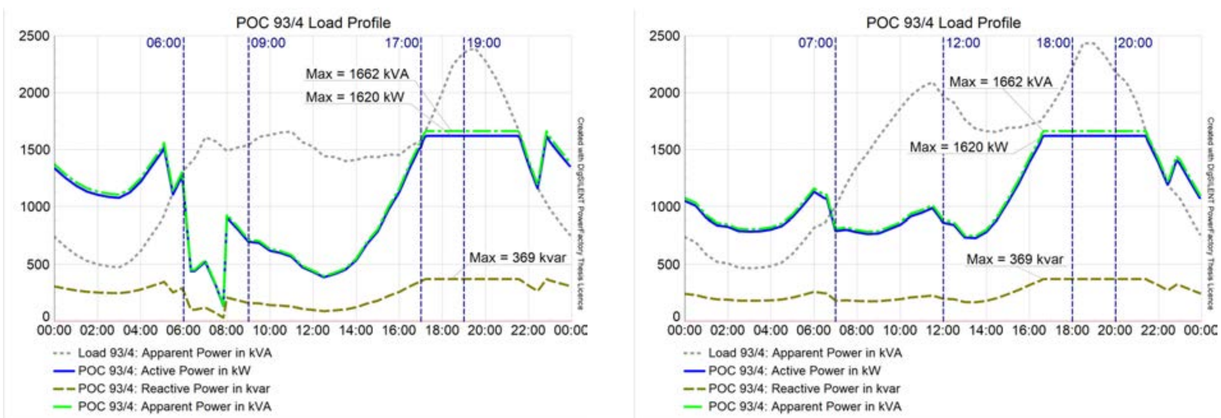
The simulated DR load profiles that include BESS operation and full PV generation are shown in Figure 4.24 and Figure 4.25.



(a) (b)

Figure 4.24. High demand non-residential DR POC load profiles.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 4.25. High demand residential DR POC load profiles.

(a) Weekday demand. (b) Weekend demand.

Results are summarised in Table 4.16 (Weekday) and Table 4.17 (Weekend) to confirm Chapter 3 first principle estimations.

Table 4.16 High demand, DR weekday calculation results.

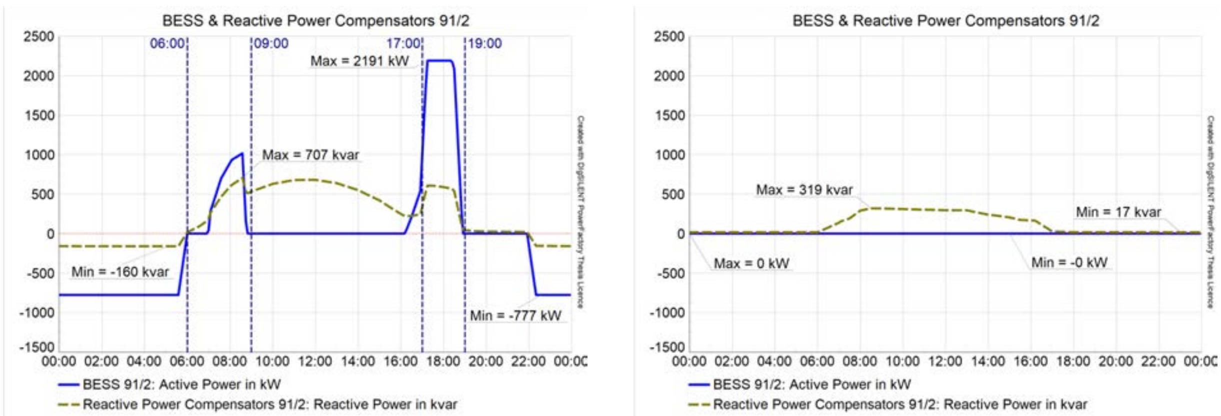
BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
MD_{POC}	2 039	2 216	430	1 455	1 662	424	kVA
$MD_{POC,P}$	1 988	2 160	419	1 419	1 620	413	kW
$MD_{POC,Q}$	453	492	96	323	369	94	kvar
LF	46%	46%	46%	65%	65%	46%	
ES_{Util}	58%	58%	58%	100%	100%	58%	
ES_S	3 405	3 701	718	0	0	708	kWh
ES_{CRR}	7%	7%	7%	14%	14%	7%	per 5 min
U_{Min}	0.9792	0.9780	0.9782	0.9787	0.9783	0.9785	pu
U_{Max}	0.9995	0.9995	0.9995	0.9994	0.9992	0.9993	pu

Table 4.17 High demand, DR weekend calculation results.

BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
MD_{POC}	608	661	128	1 455	1 662	127	kVA
$MD_{POC,P}$	593	644	125	1 419	1 620	123	kW
$MD_{POC,Q}$	135	147	29	323	369	28	kvar
LF	47%	47%	47%	68%	68%	47%	
ES_{Util}	0%	0%	0%	65%	65%	0%	
ES_S	8 065	8 765	1 701	1 057	1 207	1 677	kWh
ES_{CRR}	0%	0%	0%	7%	7%	0%	per 5 min
U_{Min}	0.9884	0.9879	0.9879	0.9880	0.9875	0.9878	pu
U_{Max}	0.9991	0.9992	0.9992	0.9991	0.9987	0.9989	pu

The POC power factors and voltage magnitudes remain within acceptable limits for all connected MV loads.

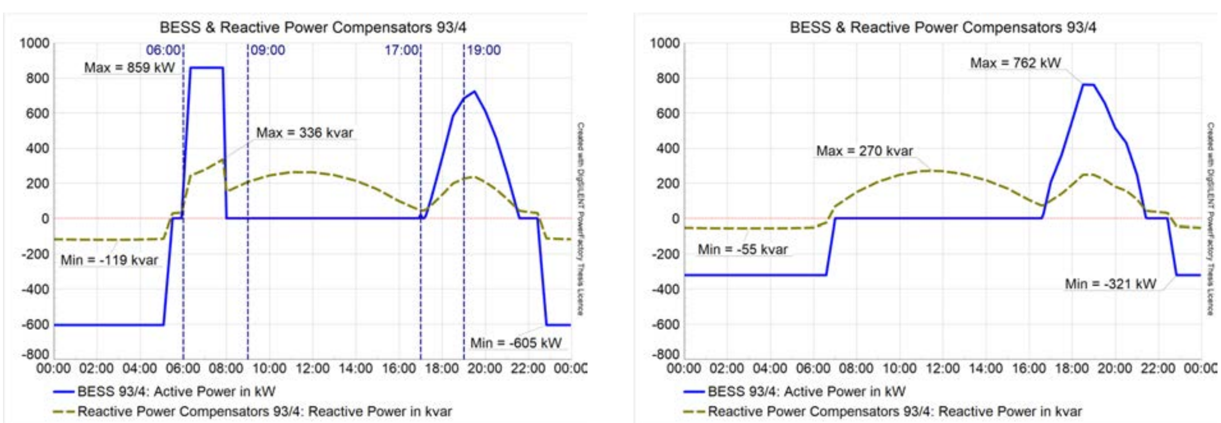
The power profiles of the BESS and reactive power compensator equipment are shown in Figure 4.26 and Figure 4.27, with the reactive power component (output or absorption) adjusted to maintain a power factor of 0.975 lagging (PF_{DR}) to ensure reactive power grid code compliance at the POC. BESS surplus discharge, as calculated in (3.60), is evident in all weekday profiles.



(a) (b)

Figure 4.26. High demand non-residential DR BESS and Compensator power.

(a) Weekday demand. (b) Weekend demand.

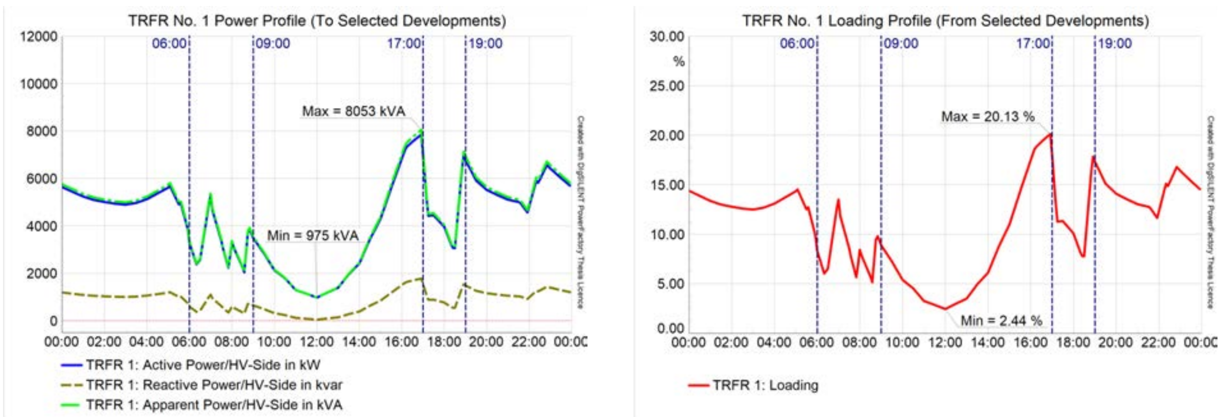


(a) (b)

Figure 4.27. High demand residential DR BESS and Compensator power.

(a) Weekday demand. (b) Weekend demand.

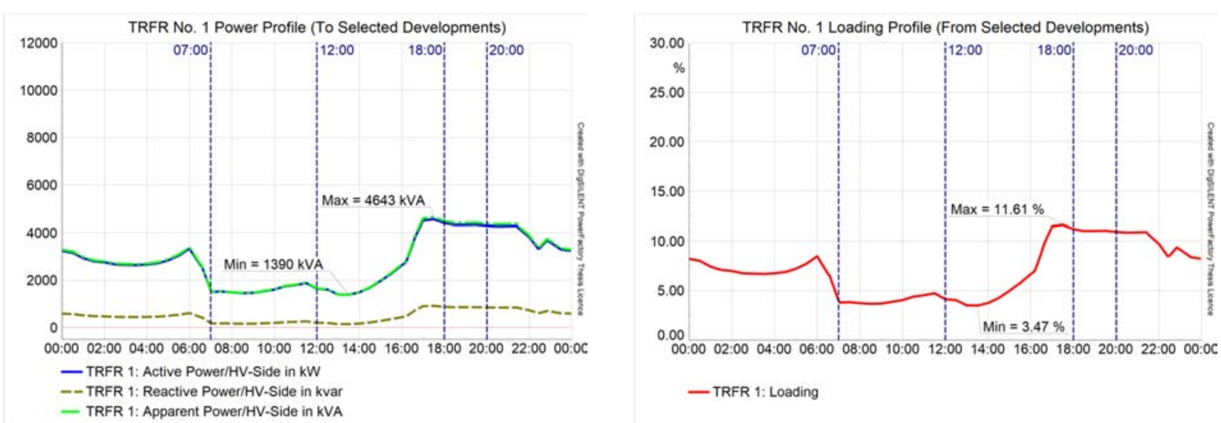
The impact of full PV generation with BESS support on the high demand primary transformer single-feed loading are shown in Figure 4.28 (weekday) and Figure 4.29 (weekend).



(a) (b)

Figure 4.28. High demand weekday primary substation transformer loading.

(a) Active, Reactive, and Apparent Power. (b) Loading percentage.



(a) (b)

Figure 4.29. High demand weekend primary substation transformer loading.

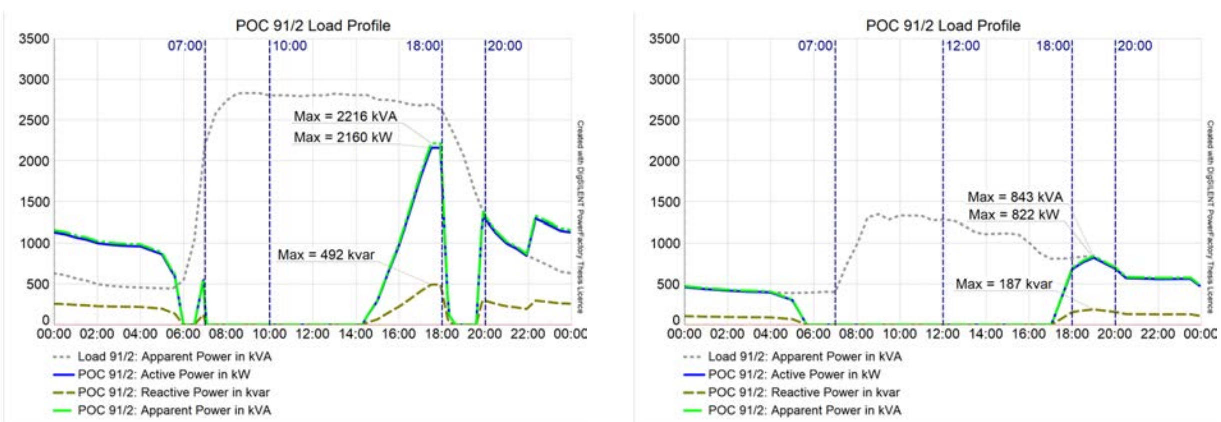
(a) Active, Reactive, and Apparent Power. (b) Loading percentage.

High demand weekday results indicate allocated loading ranging from 2.44% (975 kVA) to a maximum of 20.13% (8 053 kVA), with a development load factor of 54.37%. High demand weekend results indicate allocated loading ranging from 3.47% (1 390 kVA) to a maximum of 11.61% (4 643 kVA), with a development load factor of 60.59%.

High demand BESS integration results, with PV generation support, indicate a development maximum demand in the order of 76% (weekday) to 44% (weekend) at the primary substation when compared to the yearly maximum demand of the traditional network base case approach.

4.6.2 Low demand (BESS and PV DG active)

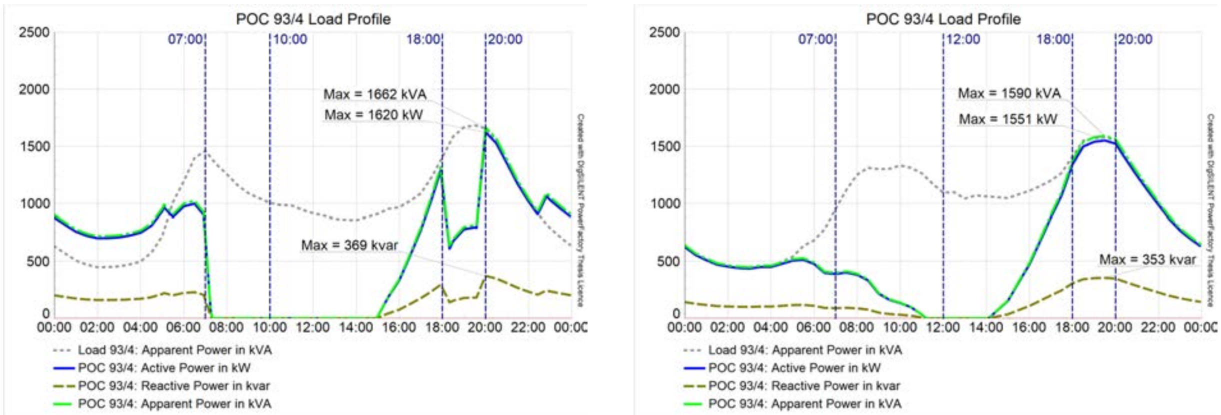
The simulated DR load profiles including BESS operation and full PV generation are shown in Figure 4.30 and Figure 4.31. For reference, see Addendum A for comparisons based on first-principle calculations.



(a) (b)

Figure 4.30. Low demand non-residential DR POC load profiles.

(a) Weekday demand. (b) Weekend demand.



(a) (b)

Figure 4.31. Low demand residential DR POC load profiles.

(a) Weekday demand. (b) Weekend demand.

Results are summarised in Table 4.18 (Weekday) and Table 4.19 (Weekend) to confirm Chapter 3 first principle estimations.

Table 4.18 Low demand, DR weekday calculation results.

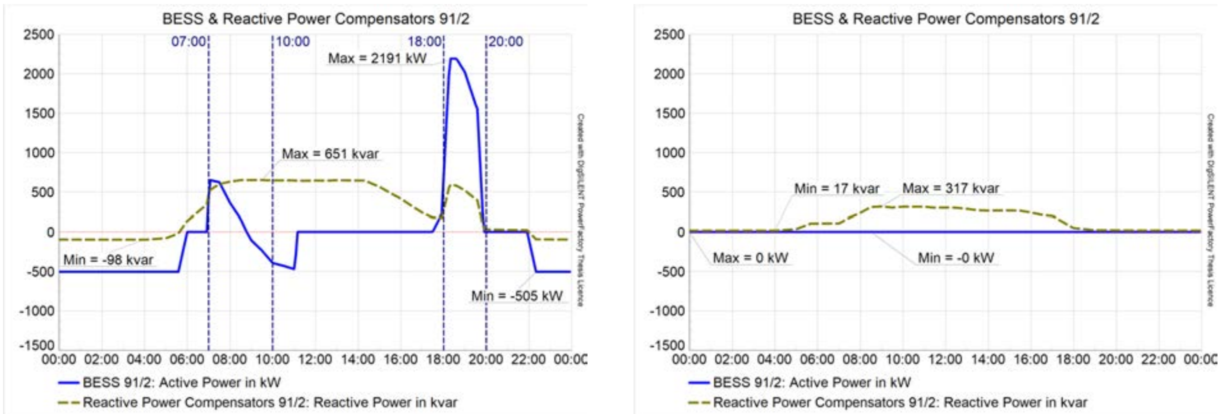
BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
MD_{POC}	2 039	2 216	430	1 455	1 662	424	kVA
$MD_{POC,P}$	1 988	2 160	419	1 419	1 620	413	kW
$MD_{POC,Q}$	453	492	96	323	369	94	kvar
LF	29%	29%	29%	36%	36%	29%	
ES_{Util}	38%	38%	38%	42%	42%	38%	
ES_S	5 036	5 473	1 062	1 755	2 003	1 047	kWh
ES_{CRR}	5%	5%	5%	6%	6%	5%	per 5 min
U_{Min}	0.9804	0.9792	0.9794	0.9799	0.9796	0.9798	pu
U_{Max}	1.0003	1.0002	1.0002	1.0002	1.0003	1.0003	pu

Table 4.19 Low demand, DR weekend calculation results.

BMK	**91/1**	**91/2**	**92/1**	**93/2**	**93/4**	**93/8**	**Unit**
$\boldsymbol{MD_{POC}}$	775	843	164	1 393	1 590	161	kVA
$\boldsymbol{MD_{POC,P}}$	756	822	160	1 358	1 551	157	kW
$\boldsymbol{MD_{POC,Q}}$	172	187	36	310	353	36	kvar
LF	32%	32%	32%	36%	36%	32%	
$\boldsymbol{ES_{Util}}$	0%	0%	0%	0%	0%	0%	
$\boldsymbol{ES_S}$	8 065	8 765	1 701	3 008	3 434	1 677	kWh
$\boldsymbol{ES_{CRR}}$	0%	0%	0%	0%	0%	0%	per 5 min
$\boldsymbol{U_{Min}}$	0.9877	0.9871	0.9872	0.9873	0.9868	0.9871	pu
$\boldsymbol{U_{Max}}$	1.0003	1.0002	1.0002	1.0002	1.0003	1.0003	pu

The POC power factors and voltage magnitudes remain within acceptable limits for all connected MV loads.

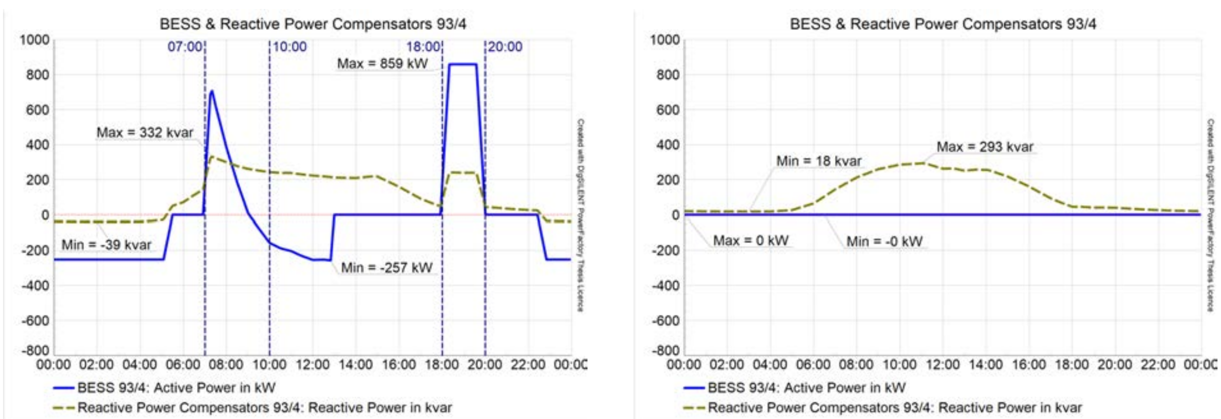
The power profiles of the BESS and reactive power compensator equipment are shown in Figure 4.32 and Figure 4.33, with the reactive power component (output or absorption) adjusted to maintain a power factor of 0.975 lagging (PF_{DR}) to ensure reactive power grid code compliance at the POC. BESS recharge from midday PV DG surplus, and surplus discharge as calculated in (3.60), is evident in all weekday profiles.



(a) (b)

Figure 4.32. Low demand non-residential DR BESS and Compensator power.

(a) Weekday demand. (b) Weekend demand.

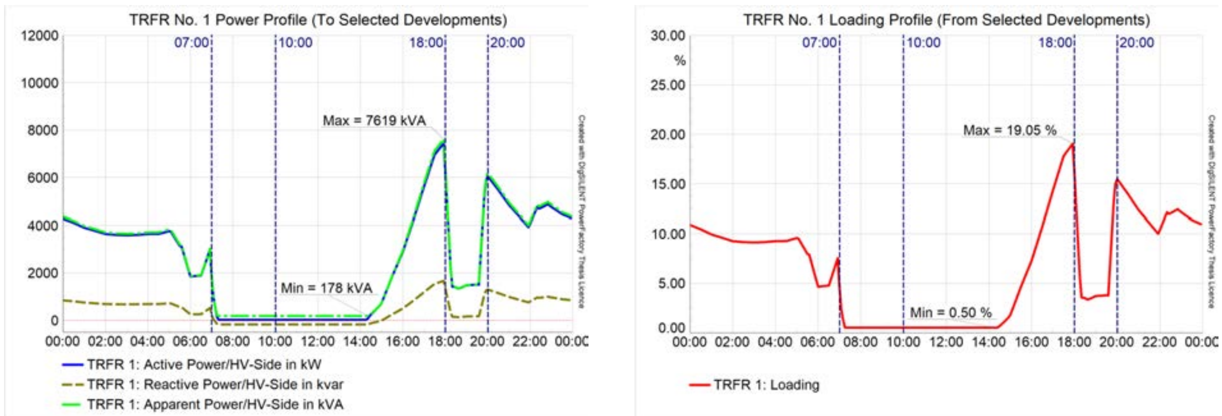


(a) (b)

Figure 4.33. Low demand residential DR BESS and Compensator power.

(a) Weekday demand. (b) Weekend demand.

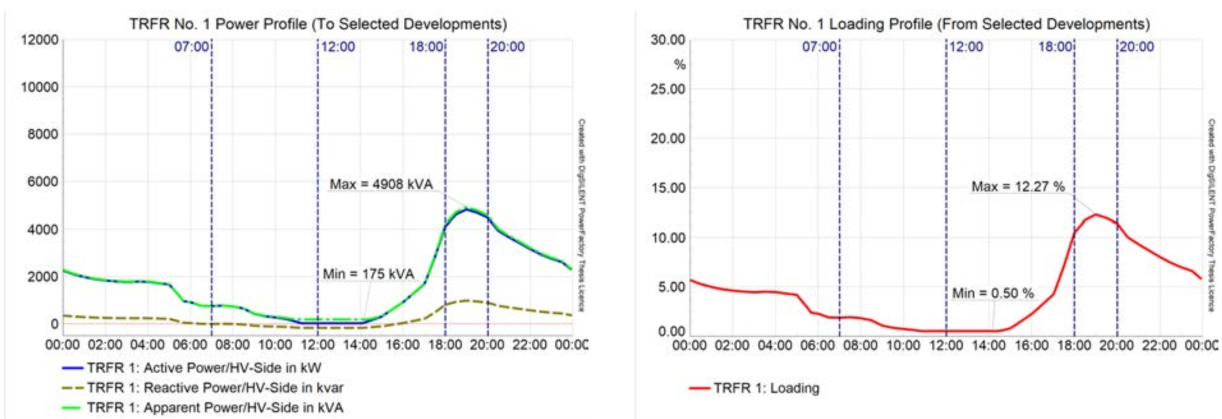
The impact of full PV generation with BESS support on the low demand primary transformer single-feed loading are shown in Figure 4.34 (weekday) and Figure 4.35 (weekend).



(a) (b)

Figure 4.34. Low demand weekday primary substation transformer loading.

(a) Active, Reactive, and Apparent Power. (b) Loading percentage.



(a) (b)

Figure 4.35. Low demand weekend primary substation transformer loading.

(a) Active, Reactive, and Apparent Power. (b) Loading percentage.

Low demand weekday results indicate allocated loading ranging from 0.50% (178 kVA) to a maximum of 19.05% (7 619 kVA), with a development load factor of 34.66%. Low demand weekend results indicate allocated loading ranging from 0.50% (175 kVA) to a maximum of 12.27% (4 908 kVA), with a development load factor of 35.06%.

Low demand BESS integration results, with PV generation support, indicate a development maximum demand in the order of 72% (weekday) to 46% (weekend) at the primary substation when compared to the yearly maximum demand of the traditional network base case approach.

4.7 COMPARISON OF RESULTS

Table 4.20 to Table 4.23 summarises the main DR integration differences compared to the traditional design (base case) scenario.

Table 4.20 Case study high demand weekday results comparison.

	Base Case	**BESS Only**	**BESS + PV**
Non-residential MD to Base Case MD	100.00%	≈ 67%	≈ 67%
Non-residential Profile *LF*	≈ 57%	≈ 86%	≈ 46%
Residential MD to Base Case MD	≈ 98%	≈ 68%	≈ 68%
Residential Profile *LF*	≈ 57%	≈ 85%	≈ 65%
Transformer Demand *LF*	65.39%	85.41%	54.37%
Transformer Minimum Loading	4.97%	7.40%	2.44%
Transformer Minimum Loading (Time)	≈ 03:00	≈ 06:20	≈ 12:00
Transformer Maximum Loading	26.50%	20.69%	20.13%
Transformer Maximum Loading (Time)	≈ 9:30	≈ 17:15 – 18:25	≈ 16:55
Transformer Loading to Base Case MD	100.00%	78.09%	75.97%

Table 4.21 Case study high demand weekend results comparison.

	Base Case	**BESS Only**	**BESS + PV**
Non-residential MD to Base Case MD	≈ 42%	≈ 41%	≈ 20%
Non-residential Profile *LF*	≈ 56%	≈ 56%	≈ 47%
Residential MD to Base Case MD	100.00%	≈ 68%	≈ 68%
Residential Profile *LF*	≈ 58%	≈ 87%	≈ 68%
Transformer Demand *LF*	63.97%	71.60%	60.59%
Transformer Minimum Loading	5.16%	7.52%	3.47%
Transformer Minimum Loading (Time)	≈ 03:30	≈ 03:30	≈ 13:30
Transformer Maximum Loading	17.45%	15.67%	11.61%
Transformer Maximum Loading (Time)	≈ 11:30	≈ 09:10	≈ 17:30
Transformer Loading to Base Case MD	65.87%	59.11%	43.80%

Table 4.22 Case study low demand weekday results comparison.

	Base Case	**BESS Only**	**BESS + PV**
Non-residential MD to Base Case MD	≈ 87%	≈ 67%	≈ 67%
Non-residential Profile *LF*	≈ 62%	≈ 82%	≈ 29%
Residential MD to Base Case MD	≈ 69%	≈ 68%	≈ 68%
Residential Profile *LF*	≈ 59%	≈ 62%	≈ 36%
Transformer Demand *LF*	67.78%	79.54%	34.66%
Transformer Minimum Loading	4.94%	3.67%	0.50%
Transformer Minimum Loading (Time)	≈ 03:00	≈ 07:20	≈ 07:20 - 14:20
Transformer Maximum Loading	22.17%	19.38%	19.05%
Transformer Maximum Loading (Time)	≈ 08:30	≈ 17:55	≈ 17:55
Transformer Loading to Base Case MD	83.66%	73.11%	71.87%

Table 4.23 Case study low demand weekend results comparison.

	Base Case	**BESS Only**	**BESS + PV**
Non-residential MD to Base Case MD	≈ 41%	≈ 41%	≈ 26%
Non-residential Profile *LF*	≈ 59%	≈ 59%	≈ 32%
Residential MD to Base Case MD	≈ 65%	≈ 65%	≈ 65%
Residential Profile *LF*	≈ 63%	≈ 63%	≈ 36%
Transformer Demand *LF*	66.30%	66.30%	35.06%
Transformer Minimum Loading	4.48%	4.45%	0.50%
Transformer Minimum Loading (Time)	≈ 03:00	≈ 03:00	≈ 11:00 - 14:20
Transformer Maximum Loading	14.15%	14.07%	12.27%
Transformer Maximum Loading (Time)	≈ 10:00	≈ 10:00	≈ 19:00
Transformer Loading to Base Case MD	53.39%	53.10%	46.30%

The internal network demands and primary transformer load factors both improve with the introduction of internal network operational peak shaving BESSs following reduced maximum demand peaks and an increasing off-peak demand governed through power flow control. With increasing BESS recharge demands during off-peak periods, the primary transformer's off-peak loading demand (traditionally the lowest loading) will increase and could shift the minimum loading to early morning or midday times (especially with the additional demand reduction from high penetration PV DG). Non-residential and low demand residential weekends do not require active BESS peak shaving operation and have no direct impact on the grid as load peaks are already well below the peak shaving setpoints.

PV DG unevenly (and exclusively) reduces midday load demands, thereby contributing to a reduced system demand and distribution losses, but also a worsening load factor. By blocking external network surplus feed-in (through renewable energy curtailment) voltage limits are not exceeded, even with maximised levels of DR penetration.

Internal networks require additional reactive power compensators (including capacitor banks) to manage reactive power in accordance with grid code requirements at the POC. This need becomes more prominent with higher levels of DR active power penetrations. Reactive power compensators could also marginally reduce the maximum demand by compensating for internal transformer reactive power requirements as seen in the non-residential BESS-only high demand weekend maximum demands.

DR equipment fault current contributions, resulting bus short-circuit level increases, and switchgear withstand capabilities, should be verified for both internal and external networks if high levels of DR integration are anticipated in downstream networks. External network fault level increases of up to 6% can be expected from downstream DR network fault contributions. External switchgear may need to be rated one I_k level above the traditional network requirements in preparation considering that future upgrades could be costly and disruptive. Changes to i_p indicate revised protection and equipment coordination requirements before energisation.

4.8 CHAPTER SUMMARY

In this Chapter an overview of the case study network design and time-based simulations was provided. Three scenarios were simulated for result comparison, namely traditional (base case without BESS integration or PV DG), BESS-only integration (without PV DG), and full DR integration (BESS and PV DG) for high and low demand seasons, weekdays and weekends.

In Section 4.2 the case study area was defined, and the authorised capacity of the network determined for electrical equipment sizing. In Section 4.3 the external and internal network areas were defined, single line diagrams created, and simulation criteria provided. In Section 4.4 the traditional network (without the integration of BESS or PV DG systems) was simulated to establish the base case traditional/expected system parameters at the individual POCs and primary substation for future integration comparative studies. In Section 4.5 the maximum sizing of BESSs was simulated for the maximum amount of demand reduction, and it was found that BESS integration (with the developed power flow control but without the contribution from the integrated PV systems) will provide a reliable method of maximum demand reduction on both internal and external infrastructure. This section represents the DR network operation with poor PV system generation capabilities. In Section 4.6 the full integration of maximum penetration BESSs and PV DG integration was considered. Power flows were proven to be successfully managed by the developed algorithm for the best integration power synergy for internal and external network benefits. In Section 4.7 a comparative result summary was provided to highlight key differences between the different DR integration levels and emphasising the advantages that integration can bring and expected changes for future integration designs.

CHAPTER 5 DISCUSSION

5.1 CHAPTER OVERVIEW

This Chapter provides an overview and evaluation of the results obtained (first principle, simulation, and case study) by explanation, interpretation, and importance/implications by addressing the research questions of Section 1.2 in support of the Chapter 6 Conclusion. Acknowledgement of limitations and practical considerations are included for future work.

Section 5.2 provides a holistic view of DR integration benefits when compared to traditional networks. Section 5.3 provides the simulation framework and an overview of the results obtained. Section 5.4 discusses the integrated BESS primary and secondary defined operations, ratings, and integration results. Section 5.5 discusses the integration of the supporting PV DG addressing the function, operation, generated surplus, ratings, and integration results. Section 5.6 discusses the combined DR system as governed by the conceptual power flow algorithm, highlighting prioritised functions, operational power control, and full DR capability integration results. Section 5.7 discusses the integration methodology followed, technical to financial trade-offs, limitations, additional integration considerations for practical application, and future work.

5.2 BENEFITS OF DR INTEGRATION

The integration of DRs offers numerous benefits spanning economic, environmental, social, technical, and policy fields. These advantages support the motivation for integrating high penetration DRs to transform and modernise the energy landscape.

Economically, DR integration reduces operational costs by decreasing transmission and distribution losses through localised generation. It also defers the need for costly upgrades to grid infrastructure, saving on capital expenditure. End-users benefit from decreased maximum demands and energy costs, provided by advanced DR system controllability. Competition and innovation driven by increasing DR integration will lead to lower energy prices, enhanced equipment efficiencies, and reduced DR equipment installation and operational costs.

Environmentally, DR integration contributes to the reduction of greenhouse gas emissions in line with global decarbonisation policies. By utilising renewable energy, DRs reduce dependency on fossil fuels and lower the carbon footprint of electricity generation. The ability of BESSs to store and manage excess renewable energy to optimally discharge during selected demand periods helps stabilise the grid and enhances the overall utilisation of higher penetration renewable resources. The installation of small-scale PV DG systems on unused spaces (such as development roofs or parking covers) minimises nature impacts.

Socially, DR integration enhances energy security and resilience. Localised energy generation and control reduce the vulnerability of developments to external network failures. In rural or undeveloped areas, the inclusion of DRs can provide a reliable and affordable energy source alternative, particularly in regions with upstream capacity constraints, thereby driving local development. The growth of the renewable and storage energy sectors will also create specialised job opportunities and trusted system integrators, stimulating economic growth.

Technically, DR integration supports grid stability and reliability. The integration of DRs allows for superior control of dynamic load and generation changes, enabling better demand response, load management, and regulation of variable renewable generation. Integrated DR systems also offer numerous grid stability advantages, ultimately providing a more balanced and efficient energy system.

Policy-wise, the benefits of DR integration align with the global energy transition goals. DRs can be leveraged to meet renewable energy targets, reduce emissions, and promote sustainable development. Effective policies and incentives supporting DR adoption can accelerate the transition towards a more resilient and sustainable energy infrastructure.

High penetration DR integration has the potential to drive economic savings (in both external and internal networks), environmental sustainability, social development, technical innovation, and policy alignment. As DR technologies continue to evolve, the comprehensive benefits they provide will become increasingly vital for a modernised electrical network.

5.3 SUMMARY OF RESULTS

The inclusion of DRs is not included in traditional reticulation network design methodologies or electrical service agreements, and should be considered in a modernised network load estimation approach. High penetration of DRs is expected in future networks as combined system levelized energy costs are soon to compete with the utility, supported by maturing technologies and trusted system integrators offering competitive integration options.

Load profile modelling forms a mandatory starting point to investigate the many additional variables and changing factors that internal network integrated distributed renewables and storage equipment will introduce to overall network parameters. Understanding load profile alterations before integration is beneficial to highlight key areas for DR improvement, such as specific energy and demand optimisations, load factor improvements, and financial trade-offs. A conceptual DR integration methodology and power flow control algorithm are therefore provided from first principles to describe the individual, followed by combined, PV DG and BESS equipment integration structures, defining the optimised operational synergy and control, and visualising the expected end-user POC profile alterations. This sets a DR integration framework and conceptual starting point prior to detailed network integration studies.

Modelling time-based load profile changes to evaluate and validate the impacts of PV DG and BESSs that include DR control for synergy enhancement, equipment ratings, and the acceptable operation of the proposed power flow control algorithms, has demonstrated to provide baseline initial operational performance criteria for system integration evaluation. Key electrical parameters evaluated to confirm acceptable DR integration include profile changes (specifically maximums for equipment ratings/utilisation), load diversity, demands and energy, load factors, PV DG and BESS operational parameters, system power control, voltage profiles, utilisation factors, reactive power requirements, fault levels, and an approach to preliminary financial implication estimations.

The equipment ratings and operation of integrated BESS and PV DG per load profile type, governed by the developed power flow control algorithm, were used to test the hypothesis by simulating integration implications within a typical mixed-use South African electrical network. The most typical profile types within reticulation networks, namely non-residential (commercial or industrial) and residential type load profiles, will act characteristically different with the introduction of DRs. This will ultimately affect profile and parameter changes observed within the upstream primary power transformers, depending on the ratio of mixed-use consumers within the shared electrical supply area. Primary substation transformer loading is below the direct sum of individual load demands following load diversification (which is not directly included in municipal service agreement guidelines). However, with the introduction of higher levels of PV DG and peak shaving BESS DRs, diversification advantages will be lost as all profiles will converge to behave similarly. Primary transformer load factors are improved with mixed-use load diversification even-though individual loads have lower load factors. This highlights the importance and role that load diversification will play in the performance of upstream network equipment.

To present comparable findings while emphasising the potential improvements that BESSs and/or PV DG support (with power control) can bring to the future of network design, three scenarios were simulated in representative seasonal weekday and weekend demands. These scenarios include “Traditional” as the comparable baseline with no BESSs or

PV DG, "Active BESS with no PV generation" for no/poor PV generation conditions (and the calculation of BESS ratings), and "Active BESS and PV Generation" with full operational BESSs and maximised output from PV DG support for complete DR integration.

Preliminary time-based profile simulations demonstrated that a significant reduction in energy, demand, and losses could be achieved with the integration of DRs, benefiting both internal network end-users and external systems all within grid code limits. A time-based simulation approach has shown significant design advantages for initial parameter and operational reviews and is recommended to be included in all preliminary renewable and storage integration compliance studies and DR control verifications.

Traditional network primary transformer maximum loading was found to occur during peak periods with the lowest loading observed during off-peak periods, aligning with expectations. With the integration of demand reduction-focused DR systems, the new reduced peak demand time will move to the midday period (following the impact of peak shaving BESS operation) or further shifted to early mornings or late afternoons where operational PV DG profiles are unable to reach. Downstream end-users with high capacity BESSs will increase the traditionally minimum off-peak period demands due to distributed BESSs recharge operation. Full output high penetration PV DG operation could further shift minimum loading to the midday period with possible generated surplus available. See Table 4.20 to Table 4.23 for result summaries.

BESSs should be rated to high demand maximums with PV DG rated to low demand profiles (to limit curtailment). Load profile forms and characteristic DR operational variances can lead to available but unused DR capacities that can be utilised more effectively and should be governed by the local power control system. In contrast to traditional single-value high demand focused static design methodologies, results indicate that the seasonal dynamics of Table 5.1 should be considered within detailed project designs (including specific DR technology operation ratings), followed by comprehensive feasibility software verification.

Table 5.1 Seasonal variables to be considered in DR equipment selection and design.

	High Demand (Winter)	**Low Demand (Summer)**
TOU Tariff Structure (Section 2.8)	Increased energy and demand costs.	Reduced energy and demand costs.
Load Profile Demands (Section 3.3)	Higher load demands for equipment sizing.	Lower load demands, below equipment sizing.
BESS Ratings (Peak shaving operation, Section 3.4)	Higher discharge required. Selected for permanent maximum demand reduction BESS ratings.	Lower discharge required. Unused peak shaving capacity available.
PV DG Output (Generation support, Section 3.5)	Possible PV output below rated maximums, reduced generation periods and magnitudes, low levels of potential PV DG surplus.	Possible PV output to rated maximums, increased generation periods and magnitudes, high levels of potential PV DG surplus.
BESS surplus capacity (Supplementary energy arbitrage operation, Section 3.6)	Higher load (higher shaving requirement), and lower PV DG output, reduces surplus BESS capacity for supplementary peak tariff arbitrage operation.	Lower load (lower shaving requirement), and higher PV DG output, increases surplus BESS capacity for supplementary peak tariff arbitrage operation.

BESS operation combined with PV DG integration support benefits the end-user by providing operational cost savings with the reduction of maximum demands and energy costs, lowering connection and bulk contribution costs during the service agreement stage, and potentially leading to a better tariffing structure. The supply authority benefits by servicing loads with a consistently reduced maximum demand and predictable load, loss, and utilisation factors (depending on PV DG penetration levels and BESS peak tariff arbitrage operation), decreased network operational/thermal losses, lower peak period network strains, and an increase in available network upstream capacity from an overall decreasing system load maximum demand, however, with the loss of mixed-use load diversity. Given the differences in high demand, low demand, weekday, and weekend profiles, all variations should be considered provided in ideally yearly load profile data.

Maximised DR operation (without network surplus energy feed-in) indicates voltage profiles well within acceptable grid code limits by limiting bi-directional/shared power flow within the internal network limits. Additional reactive power support is required following PV DG and BESS active power injections. Fault current gradings for upstream network switchgear should specifically cater to downstream network DR integration, thereby supporting the inclusion of privately connected DR systems within service agreements.

5.4 BESS OPERATION

MV BESSs were chosen as the reliable technology to permanently reduce end-user POC maximum demands as weather and other external factors do not influence BESS output as with intermittent PV generation. BESSs contribute to grid forming and integration support by providing fast response controllable power flow management through discharge capabilities at the POC, however, constitute the most expensive system levelized energy costs. Two discharge approaches (peak shaving and load following) are combined with a focus on full utilisation of BESS capacity and capabilities to relieve network strain through energy arbitrage operation, primarily targeting end-user maximum demands, followed by peak tariff energy arbitrage as a secondary function.

To reduce utility equipment strain, lower utilisation factors, and reduce power flow losses, the focus should be on maximum demand reduction and load factor improvement. Peak shaving has shown many benefits in reducing the load demand by utilising BESS discharge to specifically target remaining load maximums after initial PV DG load reductions (rather than solely prioritising financial gains through peak period arbitrage). A reduced maximum demand results in lower equipment (both internal and external network) utilisation factors and reduced power flow losses (especially during high demand periods) theoretically allowing for a permanent reduction of required electrical equipment ratings.

The best financial benefit from peak shaving operation occurs when the load demand peaks align with peak tariff periods, enabling the exploitation of a reduced maximum demand combined with peak tariff energy arbitrage. This approach does have the downside of requiring high ES capacity ratings operating over extended discharge times and potentially discharging costly BESS capacity during standard (example non-residential midday) or off-peak (example residential weekend) tariff periods should the load demand exceed the shaving setpoint value, which can negatively impact financial gains. This emphasises the supporting role of PV generated energy for initial midday load reductions, shifting BESS discharge to the most advantages cost periods for an overall improved financial advantage as governed by local control.

Load data from high demand profiles should be used to define the peak shaving BESS ratings and operational parameters to ensure an acceptable and sustainable maximum demand reduction. The peak shaving demand setpoint selected in reference to the original yearly load maximum demand (the new end-user DR maximum demand) should be higher than the increasing off-peak demands from BESS recharge. This condition should be verified within time-based profile simulations and confirmed in practice.

The methodology presented provides guidance and limits on preliminary BESS sizing. Combined with profile simulations, it demonstrated that maximum BESS peak shaving operation enabled within defined periods can achieve an absolute permanent demand reduction limit of 32% for a reduced POC maximum demand of 68% when compared to the original load maximum demand, dependent on load profile forms, BESS ratings, and defined operational periods.

Permanent maximum demand reduction through peak shaving operation is ES intensive stemming from high demand load profile ratings. This results in significant available but unused ES capacities during low demand periods or within daily load profiles where demand peaks are already below the demand shaving setpoint value. This is especially prominent within profiles with high seasonal demand differences, such as residential type loads. Additional spare ES capacity can also be provided by PV DG demand take-over or surplus PV DG BESS recharge. Provided control can utilise this spare capacity for additional peak tariff energy arbitrage operations with a focus on maximising the utilisation of installed BESS capacity. Results indicate that peak tariff energy arbitrage can therefore be selected as a secondary function to fully utilise installed capacities in periods with a low peak shaving requirement, maximising BESS utilisation for end-user cost benefits and external network strain reduction at the technical trade-off of potentially reducing BESS lifetime due to additional discharge cycles. Peak tariff energy arbitrage will be limited by the spare capacity estimated through statistical database predictions, equipment ratings, and ramp control.

High demand profiles (without the impacts of PV DG) should be selected for peak shaving operation sizing of the two main BESS components, namely ES (energy capacity) and the PCS (power recharge/discharge limits) after defining a peak shaving setpoint. High C-rates at small percentages of peak shaving could result from the high ratio of demand discharge required (kW) over a smaller installed minimum ES capacity (kWh). This can be improved by increasing/oversizing the BESS ratings (PCS and ES capacity) or investing in more expensive ES systems. Optimal operational times are dependent on load profile forms and must be selected through quasi-dynamic (time-based) simulations to verify power flow control for a permanent and sustainable enforced maximum demand reduction, and that recharge operational demands never exceed the new shaved maximum demand setpoint. BESS recharge times for reticulation system implementation should be defined within the evening off-peak tariff period for the best cost savings and improved load factors, and should not directly border expected discharge periods.

Peak shaving BESS operation without PV DG support indicates a load factor improvement if the load peaks are reduced and the minimum (off-peak) demands increased, but could also worsen load factors where ES is discharged in peak tariff energy arbitrage operation, lowering demands not necessarily contributing to daily maximums. BESS integration (without PV generation support) showed a permanently reduced external network substation transformer maximum demand in the order of 78% (downstream zoning dependant) when compared to the traditional scenario loading values.

5.5 PV DISTRIBUTED GENERATION

The intermittent nature of grid following PV DG energy systems, combined with limited generation times and possible load profile misalignment, cannot be considered as a reliable and permanent POC maximum demand reduction alternative. Increasing PV DG penetration will result in new end-user maximum demands shifting from the expected times to the mornings or late afternoons where PV energy penetration is unable to reach. PV DG has the benefit of having the cheapest levelized cost of energy and the shortest payback periods when compared to other DR technology alternatives, with energy costs already competing with grid supplied energy. High penetration system sizing should include the effective utilisation of possible generated surplus.

PV DG should be integrated as a supplementary energy source with individual inverters connected directly to the end-user main LV busses, distributed throughout the development but before the internal network MV/LV distribution transformers. This provides secondary generation close to the load for an initial low-cost demand reduction technique and BESS support. BESS support is provided by lowering midday demands to reduce peak shaving discharge requirements, followed by ES recharge (from earlier morning discharge or other uncharged ES capacity available at the time) should there be available PV DG surplus. This reduces the overall DR system payback period by prioritising a significantly cheaper levelized cost of energy when compared to standard and peak utility tariffs or equivalent BESS discharge costs. By taking over demand initially targeted for BESS peak shaving, ES capacity becomes available that can be discharged as peak tariff energy arbitrage for additional cost savings, or indirectly increase BESS lifetime through reduced BESS discharge cycles.

Commercial and industrial developments are a good fit for PV DG integration considering that operational load profiles coincide well with PV generation profiles. Increasing levels of PV_{Pen} will result in reducing midday demands and a shifting but lowering maximum demand (typically to peak tariff periods) until the demand time falls to the outside of PV generation times. As high magnitudes of standard or peak tariff demands are transferred to lower PV levelized energy costs, significant savings could be realised in both high and low demand seasons. Non-operational commercial and industrial developments could have high magnitudes of unused/curtailed PV DG surplus. In contrast, residential development maximum demands (characterised by morning and afternoon demand peaks and a general load to PV generation profile mismatch) cannot be effectively reduced with PV DG as the load demand peaks fall to the outside of the PV generation period. This limitation leads to a smaller per unit rating equivalent to the load maximum demand of maximum PV DG systems that can be installed (compared to non-residential type loads). The load to PV generation profile mismatch also results in the possibility of high generation surplus at medium levels of PV DG, even-though the daily maximum demand remains unchanged. Further contributing to high levels of residential PV DG surplus are low midday demands and significant seasonal demand differences where high PV DG output coincides with low summer demands. Residential weekend demands are generally a better match for PV DG as the initial morning peak shifts closer to the midday, however, falls within standard and off-peak tariffing periods. As residential maximum demands remain relatively unchanged with increasing PV DG penetration levels, the need for BESS integration and control for a permanent maximum demand reduction are emphasised.

If all operational load profiles of a mixed-use network are known, these core load diversification differences (such as higher residential weekend midday demands with lower demands from non-operational commercial/industrial developments, offset by, lower weekday residential demands and higher operational commercial/industrial development demands) could be used to effectively utilise all PV DG surplus for the benefit of the overall network, however, would require an advanced external network smart grid communication backbone and additional integration compliance limitations. Increasing PV_{Pen} to high levels of PV DG surplus will not significantly benefit end-users from a technical or financial perspective and could negatively impact the overall system payback period. This is because typical feed-in tariff structures are traditionally lower or comparable to PV DG LCOE, or that surplus feed-in may not be possible or allowed due to supply authority limitations. Therefore, PV DG surplus feed-in should only be considered as a potential benefit and not a core component in system sizing. Higher feed-in tariffs, privatised PPAs, or municipal incentives such as energy “Wheeling” and “Banking” will have a more favourable financial impact on surplus energy feed-in. These incentives will motivate end-users to install higher rated PV_{Pen} renewable systems (regardless of load profile coincidence) to provide diversified external network support, however, will require additional integration studies to prevent possible POC over voltages and detrimental power flows at external substations.

PV_{Pen} ratings should be based on operational low demand weekday profiles since these profiles are expected for most of the year and that generation surplus will not yield any significant cost advantages. PV DG curtailed surplus at the POC should be limited to around 5% to mitigate future system degradation and general generation irregularities. Simulations have shown that PV_{Pen} without BESS integration can be maximised to 99% for non-residential and 44% for residential applications. With maximum rated BESS integration support, these values can be increased to 104% for non-residential and 51% for residential applications. The increase in the maximum possible PV DG per unit ratings stems from the BESS utilisation of PV generated energy surplus for ES recharge or additional energy arbitrage, emphasising that the collective consideration of high penetration PV DG and BESSs should be included in time-based operational analysis for optimal design.

PV DG operation will worsen the load factor by only targeting midday demands not necessarily contributing to load maximums. PV DG could also indirectly contribute to a further worsening load factor by taking over demands originally targeted for BESS peak shaving, or providing BESS recharge, enabling additional BESS spare capacity discharged as peak period energy arbitrage.

5.6 DR INTEGRATION AND POWER FLOW CONTROL

Governing power control forms a crucial component to combine BESSs and PV DG operation as a synergistic DR system and to ensure that equipment capabilities and capacities are effectively utilised to their full potential. Optimised control amplifies the individual technology type advantages to complement (and not oppose) other operations and mitigate any drawbacks/limitations to prevent unfavourable integration conditions. The provided control harmonises changing load profiles with the integrated DR system operation, prioritising lower equivalent PV DG energy costs over more controllable (but expensive) BESS capabilities while also regulating internal system power flows. DR control, combined with reactive power compensation devices, will provide the necessary grid forming and integration support through power flow management and power factor control at the POC to meet grid code compliance criteria.

Control ensures that BESSs are functioning primarily (as prioritised) in peak-shaving operation to enforce a permanently reduced POC maximum demand, followed by the discharge of any daily surplus capacities as peak tariff energy arbitrage for additional end-user cost savings and reduced network strain. Intermittent PV DG at the individual LV loads is primarily used as a cost-effective midday load reduction source before targeted peak shaving BESS operation (thereby freeing up ES capacity for surplus peak tariff energy arbitrage or BESS recharge) and offering possible grid feed-in capability.

DRs unmanaged by a power flow control system governing BESS discharge and recharge limits could result in an increasing maximum load demand (due to incorrect charging times or having prematurely discharged all capacities required for defined peak shaving). This would contradictorily contribute to network strain, result in higher energy costs for the installer, or carry the risk of tripping the POC due to overload or other protections. Over voltages could occur when unregulated surplus PV energy production is fed back into the grid during low demand periods or contribute to a power loss increase resulting from uncontrolled/unnecessary bi-directional power flows. This necessitates an advanced local power flow controller to prioritise and regulate operational power flows to ensure operational integration technology synergy. Additionally, control is required to ensure that the DR integrated system complies with grid code requirements by providing power regulation and reactive power control (in collaboration with controllable reactive power compensator equipment as required), anti-islanding and other integration protection functionalities, and grid stability reinforcement.

PV DG curtailment forms a crucial parameter for DR control as a subcomponent of power flow regulation. POC voltage levels are kept within the grid code requirements through control and measurement by limiting bi-directional power flow internally and without external network feed-in. This in turn eliminates the uncontrollable risk that high levels of downstream DR provided generated surplus are fed into the network above the current external network demand, resulting in adverse effects such as possible protection faults/trips at the main substation, unregulated negative power flows, grid instability, and compromising utility maintenance crew safety (from the provided isolation point). As PV generation surpasses load demand after midday load take-over the surplus is prioritised to recharge any lost BESS discharge at the time as limited by equipment ratings. Any additional PV generation is then treated as an uncaptured, lost, or curtailed energy surplus.

Supported by potentially high levels of curtailed PV DG surplus, dedicated secondary PV DG surplus capture ES capacities can be included in addition to the primary storage for additional energy arbitrage or standby applications. However, this increase in capacity introduces higher complexity and is found to be unfeasible. These secondary PV DG surplus capture storage capacities and operations are still included in the conceptual control diagrams for future consideration and to indicate power flow prioritisation.

Conceptual operational considerations for the developed power flow control algorithm have shown to effectively utilise PV DG and BESS capacity and capability to benefit both end-users and the external network. This was achieved by optimising DR equipment capabilities to a changing load profile and regulating (and prioritising) internal power flows. Without dedicated control, optimised integration will not be possible and advanced equipment capabilities and effective utilisation will be lost. DR integration, as a combination of LV PV DG, MV BESSs, and control, indicates an improvement in the load factor if the load peaks are reduced and the minimum (off-peak) demands are increased through BESS primary operation. DR operation also contributes to worsening load factors with increasing levels of PV DG penetration reducing only midday demands, and surplus ES capacities discharging in peak tariff periods which doesn't necessarily contribute to daily maximums. BESS integration with full PV generation support showed a reduced external substation transformer maximum demand as downstream end-user POC maximum demands are controlled and maintained by the integrated storage systems, irrespective of available PV DG. High energy savings through downstream PV DG systems contribute to significant cost savings and an overall reduction of network strain.

Verifying full DR operation and control (including intermittent PV DG and BESS discharge/recharge cycles) in time-based operational profile simulations should therefore be required in all DR integration studies to avoid the possibility of any other unfavourable operations.

5.7 PRACTICAL CONSIDERATIONS, FUTURE WORK, AND LIMITATIONS

Integration studies and equipment sizing were conducted in the following order of priority with the objective of determining optimal integration control and the theoretical upper limits of maximum demand reduction through DR integration:

- Achieving the highest permanent maximum demand reduction possible at the POC.
- Fully utilising BESS storage capacity and capability by including high tariff energy arbitrage through surplus discharge as an additional operational benefit for higher end-user energy cost savings and external network support through reduced peak period demands.
- Fully utilising PV DG capabilities, however, limiting DG surplus external network feed-in to keep voltage profiles within limits and to maintain bi-directional power flow locally within the internal network, considering that most authorities do not provide feed-in capability (or offer very low financial returns) for surplus energy

export. This also eliminates the possibility of detrimental power flows at upstream external network substations supplying multiple loads with high levels of DG surplus.

In practice, financial feasibility recommendations will be prioritised over maximum demand reductions by assessing the full practical and financial impact of all transitioning seasons over equipment lifetime (including energy cost inflation and representative levelized energy costs) to calculate the optimal DR system cost breakeven point. This occurs when the total traditional network grid costs exceed the total DR integrated network grid and operational levelized energy costs of the DR system. Although a cost focused study will change the ratings of feasible DR systems (due to high equipment costs), the integration methodology and control will remain similar albeit with a shifted priority from the “maximum reduction of load demand” to end-user “maximised cost advantages/savings”. Selecting lower (financially feasible) DR equipment ratings with similar control will decrease load profile variations and reduce parameter changes, but with results remaining within the base case to theoretical maximum integration boundaries provided for worst-case network operation. All studies should be evaluated using detailed feasibility software (such as HOMER or similar) that considers the yearly breakeven point for the best financial feasibility to determine representative DR levelized energy costs and to assess the full practical impact of all transitioning seasons throughout the system's lifetime. With DR equipment becoming more affordable, amidst rapidly rising NSP energy costs, the breakeven year for financial feasibility will continuously decrease in future estimations.

Practical integration must comply with all requirements as per the latest local grid connection standards for renewable power plants and storage systems as proven within a GCC report. Grid-following inverter systems will reduce system inertia while increasing levels of PV DG or BESS discharge taking over higher amounts of active load demands will leave a higher reactive component to be regulated for a stable and acceptable power factor. DR inverter reactive power capabilities should therefore be verified, or alternatively additional (and expensive) dynamic reactive power compensation devices installed. The proposed (maximised-) equipment ratings and static network parameter changes provided do not include the impacts of detailed protection topologies and supporting studies such as, power quality and harmonics, reactive power equipment operation compliance (P-Q and U-Q operational envelopes), frequency and voltage responses, stability, power ramp compliance, transient/electromechanical, and other dynamic studies typically completed after obtaining specific OEM datasheets. These studies still need to be evaluated to predict the possible inclusion of other network stability and support equipment for integration compliance.

Smart control predicting the daily storage capacity requirements, including the (3.61) variance safety factor, is highly dependent on initial load database inputs and historical load data, but will become increasingly accurate as more operational data are logged for control system analysis and statistical predictions. Monitoring and control capabilities should be included for systematic internal loadshedding of non-critical loads, governed by the local control system, to maintain the reduced maximum demand at the POC (preventing trip on overload protection or exceeding service agreement conditions) in the rare instance where the shaving demand exceeds the BESS power ratings or capacity.

Detailed analysis for practical implementation should extend the typical representative profiles of this study to full yearly profiles for a more accurate load and PV DG capability baseline that includes historical weather dependent generation inefficiencies. Practical ratings and efficiencies of DR equipment, system location (for example, PV DG generation profiles and distribution power losses), and equipment lifetime output deterioration must be investigated for each individual project.

Following the same methodology, the study can be altered to smaller rated LV external network connections by shifting the MV POCs of Figure 1.1b to MV/LV distribution transformer secondaries, with the BESS connected to the same LV bus as the PV DG. Fixed PV panel positioning is assumed to consider typical development roof design, placement, orientation, and slope. However, further optimisation is possible in detailed PV DG design to maximise production (North-South orientation) or generation curve flattening (East-West orientation) to reduce BESS discharge and improve network support. BESS modelling is based on Lithium-ion parameters but can be repeated with the same method for the integration of Vanadium-flow systems with predicted reticulation network integration advantages as the technology matures. Vanadium-flow system modelling includes lower efficiencies (reduced shaving demand maximums), a slower response rate (not having a notable impact for this application), and a 100% DoD (for an increased capacity utilisation). Alternatively, considering that the available resource (PV DG and BESS) capabilities and power flow are prioritised and fully utilised by the provided power control management system, the integration methodology could be adjusted for different load profiles or additional generation sources in full off-grid applications, with the inclusion of frequency (inertia) and reactive power stability control.

It is well documented within the electrical industry, supported by smart meter readings, that municipal enforced authorised load maximum demand guideline calculations are consistently overestimated when considering actual measured data from numerous sites. This is a result of outdated municipal design guidelines not including improved energy efficient building standards, the utilisation of thermal heating and other sources of energy alternatives, internal/private energy efficiency improvements, and a general modernisation of building designs. This implies that further load profile estimation and optimisation can be achieved which did not form part of this study.

The methodology for base load maximum demand estimations enforced by supply authorities should be modernised and updated as a first step in network advancement. Reducing the load demand by implementing energy efficient installations and/or energy management in a bottom-up approach prior to DR integration is recommended to reduce the ratings of costly PV DG or ES systems required for final load reductions. Improving the accuracy of yearly load profile estimations (either statistically or through measured averages) will enable DR and utility network equipment ratings to be further optimised and prevent equipment oversizing.

5.8 CHAPTER SUMMARY

In this Chapter an overview of the Discussion was provided with result explanations in line with the initial hypotheses. The research questions of Section 1.2 were addressed and the importance of time-based studies was highlighted for the integration of DR systems.

In Section 5.2 a holistic view of DR integration benefits is provided, highlighting the overall enhancement that such integration will bring to traditional networks. In Section 5.3 an overview of the integration results was provided, supporting the crucial role that time-based studies will play within DR integration. In Section 5.4 BESS integration and mode of operations were discussed, and with optimal power control found to be the preferred method of permanent load demand reductions and additional energy arbitrage through superior (albeit expensive) discharge control provided. In Section 5.5 PV DG integration was discussed, highlighting the supporting role the technology will provide within DR integration as an initial load reduction source with the cheapest levelized energy costs for the overall improvement of the system payback period. In Section 5.6 the combined DR system is discussed, highlighting the benefits of prioritising specific technology operation and the crucial role that local power control will play. In Section 5.7 limitations are acknowledged, and additional integration considerations addressed for further study and practical implementation.

CHAPTER 6 CONCLUSION

Large inverter-based PV DG and ES systems within developer driven internal reticulation networks are not included in supply authority design guidelines, and should be considered in service agreements for a modernised network design approach. Overall network advantages provided by privately installed DR equipment can only be achieved with the effective merging of these DR systems to the external/utility network. However, the dynamic nature of PV DG and ES systems requires a more detailed time-based approach to ensure grid integration and operational compliance when compared to traditional design methodologies based only on single-value static yearly maximum demand values.

Additional variables to be considered include seasonal and daily operational changes, external factors (such as weather), and system power control, resulting in load profile variances affecting both the internal/end-user DR network and external network parameters with disturbances from either side having the possibility of interrupting the reliability, or affecting the power quality, of all shared connections. Unstudied or poorly integrated systems can result in undesirable profile alterations leading to grid complications such as increasing maximum demands, infrastructure overloads, unforeseen fault levels, worsening power factors, POC over voltages, increased power losses, additional costs (both installation and operational), and an overall reduction in system inertia, stability, and reliability.

Practical, efficient, and safe network modernisation depends on the capacity, capability, implementation, operational complexities through power management, and costs of grid integrated symbiotic DR (DG and/or ES) systems. These initial performance factors were evaluated by conducting time-based profile studies of integrated PV DG, BESSs, and optimised power control to assess the operational adaptability in response to dynamically changing load profiles.

Simulations are provided for the two main distinctive load profile forms within electrical reticulation designs, namely non-residential/commercial (weekday midday peaks and low weekend demands), and residential (morning and afternoon peaks, with lower midday demands) in a seasonal and daily representative load profile time-based operational impact study, with a methodology that can be extended to any other load profile type. Through a detailed profile optimisation analysis, the impacts of integrated DRs on network parameters were visually identified by systematically modelling load profile changes with increasing levels of integrated PV DG and BESS penetration and operation. Following individual technology type integration concepts and system impact studies, the fundamental DR operational characteristics (advantages and limitations) were identified. These operational characteristics were used to formulate the optimal power flow control algorithm for the combined DR system governing PV DG and BESS operation for both internal and external network integration synergy while mitigating any drawbacks.

Initial DR sizing and operational optimisation through time-based profile analysis (as an extension to load flow studies) have shown significant advantages for pre-integration studies. These include estimating the theoretical penetration limit, verifying power control and dynamic system operation, and evaluating network parameter impacts. Quasi-dynamic (time-based) analysis thereby forms a crucial starting point for verifying renewable generation, energy storage, and the combined DR system operation to initial grid code compliance to ensure overall network advancement, while also mitigating integration drawbacks, in the absence of external network smart grid power management capabilities. This provides crucial analytical benefits to evaluate altered network parameters (maximum demands, coincident demands, diversity, load, loss, and utilisation factors) as these affect how networks are planned and designed, impact operation and demand forecasting, and determine network installation and operational costs. These studies should be included in supply authority applications (and service agreement approvals) to evaluate DR performance factors when modernising traditional reticulation network design strategies.

Characteristic technology type integration concepts for combined DR operation have shown that intermittent and externally affected (but cost effective) PV DG is best suited for supporting generation, primary load reductions, and BESS support, while more controllable (but expensive) BESS operation provides the best advantages for targeted demand reductions through conditional energy arbitrage applications. The operational framework for the developed power flow control algorithm effectively maximises capacity utilisation and capability of synergistic combined BESS and PV DG integrated systems by regulating internal power flows to a changing load profile (keeping downstream integrated DRs bi-directional power flow within local limits without the need for a complex external network smart grid backbone) while also ensuring grid integration synergy.

Although grid interdependency has not been removed, downstream integrated DRs prioritising permanent and sustainable enforced maximum demand reductions (up to 32%), with additional peak tariff period network support, have demonstrated benefits for both internal/developer/end-user and external/utility networks. End-users benefit from operational cost savings achieved through controllable reductions in maximum demands, peak tariff demands, and energy arbitrage. These reduced downstream demands carry over to external networks, where the supply authority benefits by servicing loads with permanently reduced maximum demands and lower peak tariff period network strains, leading to increased upstream network capacity and a reduction in equipment utilisation factors. This theoretically allows for a permanent reduction of electrical equipment ratings or postponement of costly upstream system upgrades, or consequently, offers an alternative strategy for obtaining development approvals within constrained networks that would otherwise have been rejected. Integration benefits from high DR penetration profile analysis (while pending additional grid compliance studies) include improvements in load factors, voltage profiles, lower peak period strains, loading, operational/thermal losses, environmental benefits, and end-user financial gains resulting from reduced network demands. Secondary integration benefits include improved power reliability, stability and inertia, power quality, and reactive power controllability (through BESSs or supplementary reactive power compensation devices). However, these benefits come with the loss of mixed-use load diversity, additional reactive power requirements, and higher short-circuit network contributions.

The time-based integration study provides a conceptual guideline and approach for the initial design of DR integrated networks that includes, preliminary BESS and PV DG equipment sizing/ratings (and limits), DR equipment parameters impacts, approach to optimal power flow control, and preliminary cost estimation/comparison predictions following network parameter assessments. This offers a crucial background when revising traditional design methodologies, planning strategies, and feasibility study expectations, and motivates the inclusion within service agreement applications. Fundamental DR integration considerations are highlighted for integration benefits (while mitigating integration drawbacks) and the necessity of time-based (quasi-dynamic) profile studies demonstrated as the first step in modernising traditional reticulation network designs. This encourages wider adoption of higher rated privately funded developer driven renewable generation and energy storage grid integration investments providing benefits to both internal/developer/end-user and external/utility networks in preparation for a future, self-healing, reliable smart grid system.

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ADDENDUM A DR PARAMETER SOFTWARE

A.1 DR CALCULATION TOOL (EXCEL)

A detailed Excel calculation tool was created from first principles to visualise the impacts and estimate load parameters of the two main distinctive load profile types (Figure 3.2) resulting from adjustable DR penetration levels and selected power flow control operation. This includes all variables and controls as defined in Chapter 2 to Chapter 3 and forms the DR integration backbone for profile modelling studies. Although it is not possible to fully represent all program functionalities and internal software checks, key excerpts are highlighted in this Addendum. The import and processing of raw yearly measurement data are not included in the Addendum due to space limitations.

Main functionalities include the import of any yearly load profile to an adjustable ADMD, import of simulated PV DG output profiles and inefficiencies (from example PVSyst design software), changeable TOU tariff structures with energy cost inflation forecasts, and adjustable DR penetration levels managed by the selected operational power flow control scheme. Output results include preliminary equipment sizing estimations and system parameters (selectable as pu or real), and a seasonally dependent daily DR POC profile. Although the tool provides conceptual parameter changes to highlight the individual impacts of selected variables associated with DR integration, it remains an estimation/visualisation/learning tool and does not offer detailed analysis as required by grid compliance integration studies still to be completed by established power system software such as advanced power flow, short-circuit contributions, harmonic analysis, and other detailed dynamic/transient studies.

Software tool results are verified and compared to existing power system simulation software in the Chapter 4 case study. In the following subsections, verification of the non-residential low demand weekday DR POC profile (BMK 91/2) is shown with maximum (constant-) levels of BESS peak shaving and increasing levels of PV DG support up to maximum penetration (See Section 4.6.2 and Figure 4.30 for case study comparisons). Similarities to the PowerFactory DIgSILENT outputs and profile graphs can be verified for any consumer load type at any DR (PV DG and/or BESS) penetration level.

A.1.1 Main screen

The main screen of Figure A.1 provides the selectable scenario inputs, such as load ADMD, zoning (load profile form), power factor, load detail to calculate (High/Low demand, Weekday/Weekend), internal MV/LV transformer details (amount and rating, used to calculate additional active and reactive power characteristics to transformer parameters), DR (PV DG and/or BESS) penetration levels, the method of PV DG calculation (Section 3.5.1), BESS variables (Section 3.4.1), and control (Section 3.4.2 to Section 3.4.4), general network operation (feed-in availability, and applicable tariffs with yearly inflation), and other visual/reading preferences and highlights.

The tool's outputs include load parameter results, preliminary DR equipment sizing and other DR operational parameters, daily POC load profiles, and *CF* to DR-type penetration graphs (Section 2.8). In the provided example, BESS ratings are sized to 32% maximum demand peak shaving operation (Section 3.4.4) and include the full utilisation of BESS surplus capacity (Section 3.6.1). PV DG penetration is selected as the increasing variable up to the study maximum of 104% (Section 3.6.2). Output results verifies power flow control, BESS peak shaving capability, DR equipment synergy, equipment ratings and operation, and other POC parameters with increasing levels of PV_{Pen}.

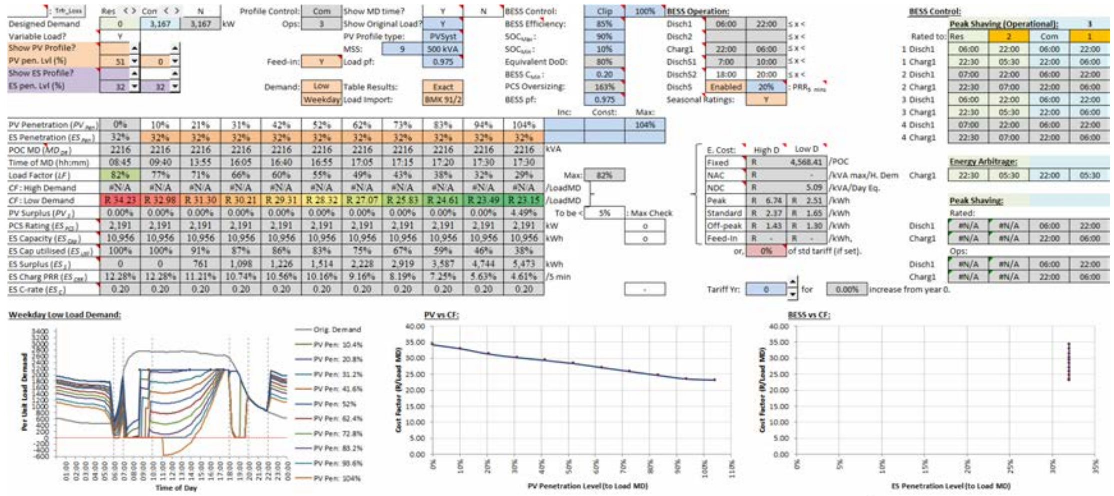

Figure A.1. Key inputs and outputs of the DR profile calculation tool.

A.1.2 Profile data

Figure A.2 summarises the processed yearly 30-minute interval measurement data before 5-minute extrapolation, PV DG profile import (from PVSyst), and the active and reactive power characteristics of MV/LV internal network transformers (315 kVA and 500 kVA).

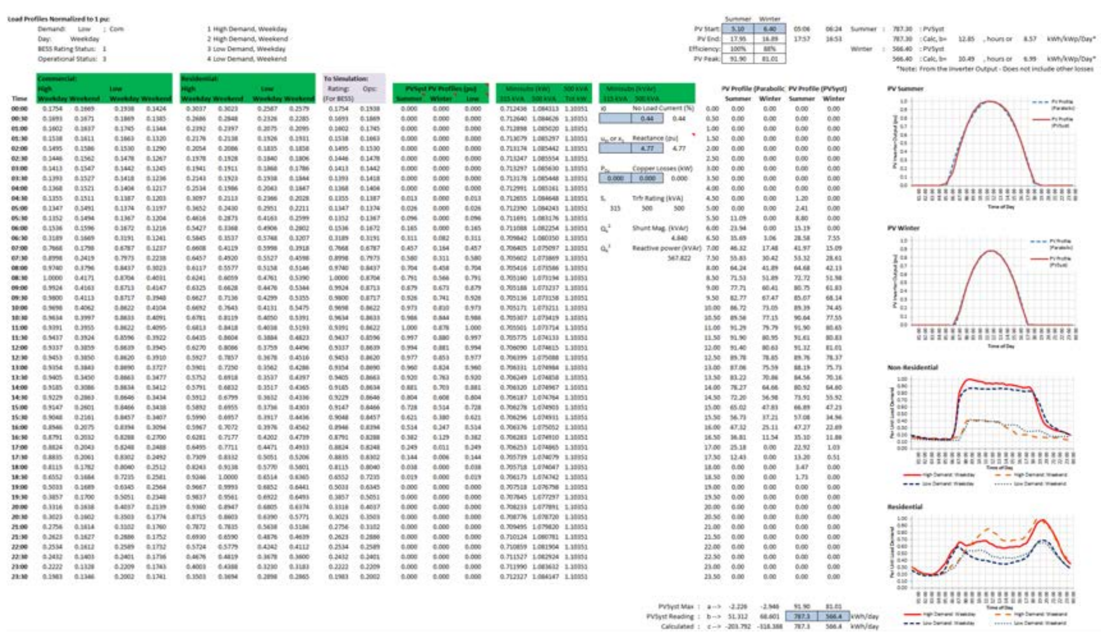

Figure A.2. Processed data of load demand and PV generation.

A.1.3 Tariff imports

Figure A.3 imports demand and energy tariff TOU structures to Figure 2.1 (Supply authority Tariff D selected [106]) and includes inputs for future forecasted tariff increase predictions. These inputs are used in *CF* estimations and financial predictions (Section 2.8).

Supply of Electricity Tariffs for the 2023/2024 Financial Year
City of Ekurhuleni
Source

CoE Tariff Select: D

	2023/2024		2022/2023		2021/2022		2020/2021		2019/2020		2018/2019	
Fixed	R 4,568.41		R 3,972.53		R 3,696.41		R 3,225.77		R 3,036.59		R 2,685.58	
NDC	R 110.72		R 96.28		R 89.59		R 78.19		R 73.60		R 65.09	
NAC	R 66.44		R 57.78		R 53.76		R 46.91		R 44.16		R 39.05	
Peak	R 6.7448	R 2.5091	R 5.8651	R 2.1819	R 5.4574	R 2.0302	R 4.7625	R 1.7717	R 4.4832	R 1.6678	R 3.9650	R 1.4750
Standard	R 2.3729	R 1.6456	R 2.0634	R 1.4310	R 1.9200	R 1.3315	R 1.6756	R 1.1619	R 1.5773	R 1.0938	R 1.3950	R 0.9674
Off-peak	R 1.4278	R 1.2977	R 1.2416	R 1.1284	R 1.1553	R 1.0500	R 1.0082	R 0.9163	R 0.9491	R 0.8626	R 0.8394	R 0.7629
Yearly Increase:	15.00%		7.47%		14.59%		6.23%		13.07%			
Peak / Std:	284.24%	152.47%	284.24%	152.47%	284.24%	152.47%	284.23%	152.48%	284.23%	152.48%	284.23%	152.47%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Off-peak / Std:	60.17%	78.86%	60.17%	78.85%	60.17%	78.86%	60.17%	78.86%	60.17%	78.86%	60.17%	78.86%

Future increase/year:

Year 1	10.00%
Year 2	13.00%
Year 3+	13.00%

Percentage Increase Calcs:

Year:	HD Std	LD Std		
0	R 2.373	R 1.646	1.00	0.00%
1	R 2.610	R 1.810	1.10	10.00%
2	R 2.950	R 2.045	1.24	24.30%
3	R 3.333	R 2.311	1.40	40.46%
4	R 3.766	R 2.612	1.59	58.72%
5	R 4.256	R 2.951	1.79	79.35%
6	R 4.809	R 3.335	2.03	102.67%
7	R 5.434	R 3.769	2.29	129.01%
8	R 6.141	R 4.259	2.59	158.79%
9	R 6.939	R 4.812	2.92	192.43%
10	R 7.841	R 5.438	3.30	230.44%
11	R 8.860	R 6.145	3.73	273.40%
12	R 10.012	R 6.944	4.22	321.94%
13	R 11.314	R 7.846	4.77	376.80%
14	R 12.785	R 8.866	5.39	438.78%
15	R 14.447	R 10.019	6.09	508.82%
16	R 16.325	R 11.321	6.88	587.97%
17	R 18.447	R 12.793	7.77	677.41%
18	R 20.845	R 14.456	8.78	778.47%
19	R 23.555	R 16.335	9.93	892.67%
20	R 26.617	R 18.459	11.22	1021.72%

Figure A.3. Importing tariff structures and forecasted energy cost inflation rates.

A.1.4 Calculation tables

The calculation tables of Figure A.4 to Figure A.15 form the primary component of the software that calculates the outputs displayed in the main screen (Figure A.1), taking into account all project inputs per defined load, DR details, and mode of operation. Due to space limitations, the data in Figure A.4 to Figure A.15 have been filtered to display only zero, middle, and maximum levels of PV_{Pen}.

										0			1			2		
	Low	Weekday	Load Demand		Calculated PV Profiles			ES State	ES State	ES System Ratings (No PV)			ES System Reserve (No PV)			ES & PV Ops (No Surplus Used)		
Time	Norm. data (pu)		Real, incl. MSS		Com	5	10	Rating	Ops.	Com	5	10	Com	5	10	Com	5	10
	Ops:	ES Rating:	Ops:	ES Rating:						68%	68%	68%						
00:00	0.194	0.175	623.850	565.402	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:05	0.193	0.174	620.179	562.192	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:10	0.192	0.173	616.509	558.982	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:15	0.190	0.172	612.838	555.772	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:20	0.189	0.171	609.167	552.562	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:25	0.188	0.170	605.496	549.352	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:30	0.187	0.169	601.826	546.142	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:35	0.185	0.168	595.314	541.318	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:40	0.183	0.166	588.802	536.495	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:45	0.181	0.165	582.291	531.671	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:50	0.179	0.163	575.779	526.848	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:55	0.177	0.162	569.267	522.025	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:00	0.175	0.160	562.755	517.201	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:05	0.173	0.159	558.387	513.827	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:10	0.172	0.158	554.018	510.453	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:15	0.170	0.157	549.649	507.078	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:20	0.169	0.156	545.281	503.704	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:25	0.168	0.155	540.912	500.330	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:30	0.166	0.154	536.543	496.956	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:35	0.164	0.153	529.553	494.726	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:40	0.162	0.152	522.563	492.497	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:45	0.160	0.152	515.573	490.267	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:50	0.157	0.151	508.583	488.038	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:55	0.155	0.150	501.593	485.809	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:00	0.153	0.150	494.603	483.579	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:05	0.152	0.149	491.828	480.955	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:10	0.151	0.148	489.053	478.331	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:15	0.150	0.147	486.278	475.707	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:20	0.150	0.146	483.503	473.083	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:25	0.149	0.145	480.728	470.459	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:30	0.148	0.145	477.953	467.835	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:35	0.147	0.144	476.049	466.096	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:40	0.147	0.143	474.145	464.356	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:45	0.146	0.143	472.242	462.617	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:50	0.145	0.142	470.338	460.878	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:55	0.145	0.142	468.435	459.138	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:00	0.144	0.141	466.531	457.399	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:05	0.144	0.141	465.296	456.335	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:10	0.143	0.141	464.061	455.271	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:15	0.143	0.140	462.827	454.207	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:20	0.143	0.140	461.592	453.142	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:25	0.142	0.140	460.357	452.078	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:30	0.142	0.139	459.122	451.014	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:35	0.142	0.139	458.371	449.714	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:40	0.141	0.138	457.620	448.414	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:45	0.141	0.138	456.869	447.114	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:50	0.141	0.138	456.118	445.814	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:55	0.141	0.137	455.367	444.515	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:00	0.140	0.137	454.616	443.215	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:05	0.140	0.137	453.734	442.536	0.000	3.597	7.193	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:10	0.140	0.136	452.852	441.858	0.000	7.193	14.386	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:15	0.140	0.136	451.970	441.180	0.000	10.790	21.579	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:20	0.139	0.136	451.089	440.502	0.000	14.386	28.772	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:25	0.139	0.136	450.207	439.824	0.000	17.983	35.966	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:30	0.139	0.136	449.325	439.146	0.000	21.579	43.159	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:35	0.139	0.135	448.638	438.742	0.000	25.182	50.364	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:40	0.138	0.135	447.950	438.338	0.000	28.784	57.569	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:45	0.138	0.135	447.263	437.935	0.000	32.387	64.774	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:50	0.138	0.135	446.575	437.531	0.000	35.989	71.979	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:55	0.138	0.135	445.888	437.127	0.000	39.592	79.184	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:00	0.137	0.135	445.200	436.723	0.000	43.195	86.389	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:05	0.137	0.135	444.820	436.938	0.000	62.278	124.555	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:10	0.137	0.135	444.440	437.153	0.000	81.361	162.722	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:15	0.137	0.135	444.060	437.368	0.000	100.444	200.888	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:20	0.137	0.135	443.680	437.583	0.000	119.527	239.055	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:25	0.137	0.135	443.300	437.798	0.000	138.610	277.221	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:30	0.137	0.135	442.920	438.013	0.000	157.694	315.387	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:35	0.142	0.138	459.024	447.753	0.000	176.777	353.554	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:40	0.147	0.141	475.128	457.493	0.000	195.860	391.720	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:45	0.152	0.144	491.232	467.234	0.000	214.943	429.886	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:50	0.157	0.147	507.337	476.974	0.000	234.026	468.053	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:55	0.162	0.151	523.441	486.714	0.000	253.110	506.219	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:00	0.167	0.154	539.545	496.455	0.000	272.193	544.386	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:05	0.193	0.181	619.720	583.685	0.000	312.186	624.372	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:10	0.218	0.209	699.894	670.915	0.000	352.180	704.359	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Figure A.4. Calculation tables (00:00 to 06:10 - Part 1/3).

	3			4			5			6			7			8		
	ES & PV (ES Arbitrage Used)			PV Surplus (Avail. for ES use)			ES profile including PV recharg			PV Surplus (For Rem. use)			ES Spare profile			PV Surplus (All ES Charged)		
Time	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com	5	10
00:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:05	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:10	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:15	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:25	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:30	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
00:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:05	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:10	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:15	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:25	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:30	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
01:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:05	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:10	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:15	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:25	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:30	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
02:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:05	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:10	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:15	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:25	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:30	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
03:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:05	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:10	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:15	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:25	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:30	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
04:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:05	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:10	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:15	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:25	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:30	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
05:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:00	0.000	0.000	0.000	0.000	0.000	-4.840	0.000	0.000	0.000	0.000	0.000	-4.840	0.000	0.000	0.000	0.000	0.000	-4.840
06:05	0.000	0.000	0.000	0.000	0.000	-4.653	0.000	0.000	0.000	0.000	0.000	-4.653	0.000	0.000	0.000	0.000	0.000	-4.653
06:10	0.000	0.000	0.000	0.000	0.000	-4.465	0.000	0.000	0.000	0.000	0.000	-4.465	0.000	0.000	0.000	0.000	0.000	-4.465

Figure A.5. Calculation tables (00:00 to 06:10 - Part 2/3).

	9															
	ES to be recharged by grid			ES Profiles Clip (ES Calc)			ES Capacity Profile			BESS Maximim PRR			After DR Demand (at POC)			Tariff
Time	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com (Var)	5	10	Select 3
00:00	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1968.857	1736.519	1128.953	O
00:05	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1965.187	1732.848	1125.282	O
00:10	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1961.516	1729.177	1121.612	O
00:15	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1957.845	1725.507	1117.941	O
00:20	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1954.174	1721.836	1114.270	O
00:25	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1950.504	1718.165	1110.599	O
00:30	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1946.833	1714.494	1106.928	O
00:35	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1940.321	1707.983	1100.417	O
00:40	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1933.809	1701.471	1093.905	O
00:45	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1927.298	1694.959	1087.393	O
00:50	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1920.786	1688.448	1080.882	O
00:55	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1914.274	1681.936	1074.370	O
01:00	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1907.763	1675.424	1067.858	O
01:05	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1903.394	1671.055	1063.490	O
01:10	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1899.025	1666.687	1059.121	O
01:15	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1894.656	1662.318	1054.752	O
01:20	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1890.288	1657.949	1050.383	O
01:25	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1885.919	1653.581	1046.015	O
01:30	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1881.550	1649.212	1041.646	O
01:35	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1874.560	1642.222	1034.656	O
01:40	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1867.570	1635.232	1027.666	O
01:45	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1860.580	1628.242	1020.676	O
01:50	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1853.590	1621.252	1013.686	O
01:55	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1846.600	1614.262	1006.696	O
02:00	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1839.610	1607.272	999.706	O
02:05	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1836.835	1604.497	996.931	O
02:10	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1834.060	1601.722	994.156	O
02:15	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1831.285	1598.947	991.381	O
02:20	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1828.510	1596.172	988.606	O
02:25	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1825.735	1593.396	985.831	O
02:30	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1822.960	1590.621	983.056	O
02:35	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1821.056	1588.718	981.152	O
02:40	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1819.153	1586.814	979.248	O
02:45	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1817.249	1584.911	977.345	O
02:50	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1815.345	1583.007	975.441	O
02:55	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1813.442	1581.103	973.537	O
03:00	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1811.538	1579.200	971.634	O
03:05	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1810.303	1577.965	970.399	O
03:10	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1809.069	1576.730	969.164	O
03:15	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1807.834	1575.495	967.929	O
03:20	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1806.599	1574.261	966.695	O
03:25	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1805.364	1573.026	965.460	O
03:30	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1804.129	1571.791	964.225	O
03:35	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1803.378	1571.040	963.474	O
03:40	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1802.627	1570.289	962.723	O
03:45	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1801.876	1569.538	961.972	O
03:50	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1801.125	1568.786	961.221	O
03:55	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1800.374	1568.035	960.470	O
04:00	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1799.623	1567.284	959.718	O
04:05	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1798.741	1562.806	951.644	O
04:10	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1797.859	1558.328	943.569	O
04:15	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1796.977	1553.849	935.494	O
04:20	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1796.096	1549.371	927.419	O
04:25	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1795.214	1544.893	919.344	O
04:30	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1794.332	1540.414	911.269	O
04:35	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1793.645	1536.124	903.377	O
04:40	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1792.957	1531.834	895.484	O
04:45	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1792.270	1527.544	887.592	O
04:50	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1791.582	1523.254	879.699	O
04:55	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1790.895	1518.964	871.806	O
05:00	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1790.207	1514.674	863.914	O
05:05	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1789.827	1495.211	825.367	O
05:10	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1789.447	1475.748	786.821	O
05:15	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1789.067	1456.284	748.275	O
05:20	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1788.687	1436.821	709.728	O
05:25	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1788.307	1417.358	671.182	O
05:30	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1787.927	1397.895	632.635	O
05:35	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1804.031	1394.916	610.573	O
05:40	0.000	0.000	0.000	-1076.006	-890.135	-404.082				12%	10%	5%	1551.134	1169.403	487.490	O
05:45	0.000	0.000	0.000	-807.004	-667.601	-303.062				12%	10%	5%	1298.237	943.890	364.408	O
05:50	0.000	0.000	0.000	-538.003	-445.067	-202.041				12%	10%	5%	1045.340	718.378	241.325	O
05:55	0.000	0.000	0.000	-269.001	-222.534	-101.021				12%	10%	5%	792.442	492.865	118.242	O
06:00	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%	12%	10%	5%	539.545	267.352	-4.840	S
06:05	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%				619.720	307.533	-4.653	S
06:10	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%				699.894	347.715	-4.465	S

Figure A.6. Calculation tables (00:00 to 06:10 - Part 3/3).

										0			1			2		
	Low	Weekday	Load Demand		Calculated PV Profiles			ES State	ES State	ES System Ratings (No PV)			ES System Reserve (No PV)			ES & PV Ops (No Surplus Used)		
Time	Norm. data (pu)		Real, incl. MSS		Com	5	10	Rating	Ops.	Com	5	10	Com	5	10	Com	5	10
	Ops:	ES Rating:	Ops:	ES Rating:						68%	68%	68%						
06:15	0.243	0.236	780.069	758.145	0.000	392.173	784.346	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:20	0.268	0.264	860.243	845.375	0.000	432.167	864.333	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:25	0.294	0.291	940.418	932.605	0.000	472.160	944.320	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:30	0.319	0.319	1020.592	1019.835	0.000	512.154	1024.307	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:35	0.379	0.394	1210.435	1256.280	0.000	552.147	1104.294	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:40	0.439	0.468	1400.278	1492.726	0.000	592.141	1184.281	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:45	0.499	0.543	1590.120	1729.172	0.000	632.134	1264.268	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:50	0.559	0.617	1779.963	1965.618	0.000	672.127	1344.255	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:55	0.619	0.692	1969.806	2202.064	0.000	712.121	1424.242	Disch1	Disch1	41.551	41.551	41.551	0.000	0.000	0.000	0.000	0.000	0.000
07:00	0.679	0.767	2159.648	2438.510	0.000	752.114	1504.229	Disch1	Disch1	277.997	277.997	277.997	0.000	0.000	0.000	0.000	0.000	0.000
07:05	0.698	0.789	2222.234	2508.751	0.000	786.038	1572.077	Disch1	Disch1	348.238	348.238	348.238	61.721	61.721	61.721	61.721	0.000	0.000
07:10	0.718	0.811	2284.819	2578.992	0.000	819.962	1639.925	Disch1	Disch1	418.480	418.480	418.480	124.307	124.307	124.307	124.307	0.000	0.000
07:15	0.738	0.833	2347.404	2649.233	0.000	853.887	1707.773	Disch1	Disch1	488.721	488.721	488.721	186.892	186.892	186.892	186.892	0.000	0.000
07:20	0.758	0.855	2409.990	2719.474	0.000	887.811	1775.621	Disch1	Disch1	558.962	558.962	558.962	249.478	249.478	249.478	249.478	0.000	0.000
07:25	0.778	0.878	2472.575	2789.715	0.000	921.735	1843.469	Disch1	Disch1	629.203	629.203	629.203	312.063	312.063	312.063	312.063	0.000	0.000
07:30	0.797	0.900	2535.161	2859.957	0.000	955.659	1911.317	Disch1	Disch1	699.444	699.444	699.444	374.648	374.648	374.648	374.648	0.000	0.000
07:35	0.805	0.912	2559.679	2899.125	0.000	989.583	1979.165	Disch1	Disch1	738.612	738.612	738.612	399.167	399.167	399.167	399.167	0.000	0.000
07:40	0.813	0.925	2584.197	2938.293	0.000	1023.507	2047.013	Disch1	Disch1	777.780	777.780	777.780	423.685	423.685	423.685	423.685	0.000	0.000
07:45	0.821	0.937	2608.715	2977.461	0.000	1057.431	2114.861	Disch1	Disch1	816.948	816.948	816.948	448.203	448.203	448.203	448.203	0.000	0.000
07:50	0.828	0.949	2633.233	3016.629	0.000	1091.355	2182.709	Disch1	Disch1	856.116	856.116	856.116	472.721	472.721	472.721	472.721	0.000	0.000
07:55	0.836	0.962	2657.751	3055.797	0.000	1125.279	2250.558	Disch1	Disch1	895.284	895.284	895.284	497.239	497.239	497.239	497.239	0.000	0.000
08:00	0.844	0.974	2682.269	3094.965	0.000	1159.203	2318.406	Disch1	Disch1	934.452	934.452	934.452	521.757	521.757	521.757	521.757	0.000	0.000
08:05	0.848	0.978	2696.327	3108.675	0.000	1183.198	2366.397	Disch1	Disch1	948.162	948.162	948.162	535.815	535.815	535.815	535.815	0.000	0.000
08:10	0.853	0.983	2710.384	3122.384	0.000	1207.194	2414.388	Disch1	Disch1	961.872	961.872	961.872	549.872	549.872	549.872	549.872	0.000	0.000
08:15	0.857	0.987	2724.442	3136.094	0.000	1231.189	2462.379	Disch1	Disch1	975.582	975.582	975.582	563.930	563.930	563.930	563.930	0.000	0.000
08:20	0.861	0.991	2738.500	3149.804	0.000	1255.185	2510.370	Disch1	Disch1	989.292	989.292	989.292	577.987	577.987	577.987	577.987	0.000	0.000
08:25	0.866	0.996	2752.557	3163.514	0.000	1279.180	2558.360	Disch1	Disch1	1003.002	1003.002	1003.002	592.045	592.045	592.045	592.045	0.000	0.000
08:30	0.870	1.000	2766.615	3177.224	0.000	1303.176	2606.351	Disch1	Disch1	1016.712	1016.712	1016.712	606.103	606.103	606.103	606.103	0.000	0.000
08:35	0.871	0.999	2767.094	3173.227	0.000	1327.171	2654.342	Disch1	Disch1	1012.715	1012.715	1012.715	606.581	606.581	606.581	606.581	0.000	0.000
08:40	0.871	0.997	2767.572	3169.231	0.000	1351.167	2702.333	Disch1	Disch1	1008.718	1008.718	1008.718	607.060	607.060	607.060	607.060	0.000	0.000
08:45	0.871	0.996	2768.051	3165.234	0.000	1375.162	2750.324	Disch1	Disch1	1004.722	1004.722	1004.722	607.539	607.539	607.539	607.539	0.000	0.000
08:50	0.871	0.995	2768.529	3161.238	0.000	1399.158	2798.315	Disch1	Disch1	1000.725	1000.725	1000.725	608.017	608.017	608.017	608.017	0.000	0.000
08:55	0.871	0.994	2769.008	3157.241	0.000	1423.153	2846.306	Disch1	Disch1	996.729	996.729	996.729	608.496	608.496	608.496	608.496	0.000	0.000
09:00	0.871	0.992	2769.487	3153.244	0.000	1447.149	2894.297	Disch1	Disch1	992.732	992.732	992.732	608.974	608.974	608.974	608.974	0.000	0.000
09:05	0.871	0.990	2769.726	3146.672	0.000	1460.052	2920.104	Disch1	Disch1	986.160	986.160	986.160	609.214	609.214	609.214	609.214	0.000	0.000
09:10	0.871	0.988	2769.966	3140.099	0.000	1472.956	2945.911	Disch1	Disch1	979.587	979.587	979.587	609.454	609.454	609.454	609.454	0.000	0.000
09:15	0.871	0.986	2770.206	3133.527	0.000	1485.859	2971.718	Disch1	Disch1	973.014	973.014	973.014	609.693	609.693	609.693	609.693	0.000	0.000
09:20	0.872	0.984	2770.445	3126.954	0.000	1498.763	2997.526	Disch1	Disch1	966.442	966.442	966.442	609.933	609.933	609.933	609.933	0.000	0.000
09:25	0.872	0.982	2770.685	3120.382	0.000	1511.666	3023.333	Disch1	Disch1	959.869	959.869	959.869	610.173	610.173	610.173	610.173	0.000	0.000
09:30	0.872	0.980	2770.924	3113.809	0.000	1524.570	3049.140	Disch1	Disch1	953.297	953.297	953.297	610.412	610.412	610.412	610.412	0.000	0.000
09:35	0.870	0.978	2765.897	3108.437	0.000	1537.473	3074.947	Disch1	Disch1	947.925	947.925	947.925	605.384	605.384	605.384	605.384	0.000	0.000
09:40	0.869	0.977	2760.869	3103.066	0.000	1550.377	3100.754	Disch1	Disch1	942.553	942.553	942.553	600.356	600.356	600.356	600.356	0.000	0.000
09:45	0.867	0.975	2755.841	3097.694	0.000	1563.280	3126.561	Disch1	Disch1	937.182	937.182	937.182	595.329	595.329	595.329	595.329	0.000	0.000
09:50	0.865	0.973	2750.813	3092.322	0.000	1576.184	3152.368	Disch1	Disch1	931.810	931.810	931.810	590.301	590.301	590.301	590.301	0.000	0.000
09:55	0.864	0.971	2745.785	3086.951	0.000	1589.087	3178.175	Disch1	Disch1	926.438	926.438	926.438	585.273	585.273	585.273	585.273	0.000	0.000
10:00	0.862	0.970	2740.757	3081.579	0.000	1601.991	3203.982	Disch1	Disch1	921.067	921.067	921.067	580.245	580.245	580.245	580.245	0.000	0.000
10:05	0.862	0.969	2741.359	3078.216	0.000	1605.741	3211.482	Disch1	Disch1	917.703	917.703	917.703	580.847	580.847	580.847	580.847	0.000	0.000
10:10	0.863	0.968	2741.961	3074.852	0.000	1609.491	3218.982	Disch1	Disch1	914.340	914.340	914.340	581.449	581.449	581.449	581.449	0.000	0.000
10:15	0.863	0.967	2742.563	3071.489	0.000	1613.241	3226.482	Disch1	Disch1	910.977	910.977	910.977	582.051	582.051	582.051	582.051	0.000	0.000
10:20	0.863	0.966	2743.165	3068.126	0.000	1616.991	3233.983	Disch1	Disch1	907.613	907.613	907.613	582.653	582.653	582.653	582.653	0.000	0.000
10:25	0.863	0.964	2743.767	3064.762	0.000	1620.741	3241.483	Disch1	Disch1	904.250	904.250	904.250	583.255	583.255	583.255	583.255	0.000	0.000
10:30	0.863	0.963	2744.369	3061.399	0.000	1624.492	3248.983	Disch1	Disch1	900.887	900.887	900.887	583.857	583.857	583.857	583.857	0.000	0.000
10:35	0.863	0.959	2743.791	3048.552	0.000	1628.242	3256.483	Disch1	Disch1	888.040	888.040	888.040	583.279	583.279	583.279	583.279	0.000	0.000
10:40	0.863	0.955	2743.213	3035.706	0.000	1631.992	3263.983	Disch1	Disch1	875.193	875.193	875.193	582.701	582.701	582.701	582.701	0.000	0.000
10:45	0.863	0.951	2742.635	3022.859	0.000	1635.742	3271.484	Disch1	Disch1	862.346	862.346	862.346	582.123	582.123	582.123	582.123	0.000	0.000
10:50	0.863	0.947	2742.057	3010.012	0.000	1639.492	3278.984	Disch1	Disch1	849.500	849.500	849.500	581.545	581.545	581.545	581.545	0.000	0.000
10:55	0.862	0.943	2741.479	2997.165	0.000	1643.242	3286.484	Disch1	Disch1	836.653	836.653	836.653	580.967	580.967	580.967	580.967	0.000	0.000
11:00	0.862	0.939	2740.901	2984.318	0.000	1646.992	3293.984	Disch1	Disch1	823.806	823.806	823.806	580.389	580.389	580.389	580.389	0.000	0.000
11:05	0.862	0.940	2739.483	2986.750	0.000	1646.132	3292.264	Disch1	Disch1	826.238	826.238	826.238	578.970	578.970	578.970	578.970	0.000	0.000
11:10	0.861	0.941	2738.064	2989.182	0.000	1645.272	3290.543	Disch1	Disch1	828.670	828.670	828.670	577.552	577.552	577.552	577.552	0.000	0.000
11:15	0.861	0.941	2736.645	2991.614	0.000	1644.411	3288.823	Disch1	Disch1	831.102	831.102	831.102	576.133	576.133	576.133	576.133	0.000	0.000
11:20	0.860	0.942	2735.226	2994.046	0.000	1643.551	3287.102	Disch1	Disch1	833.534	833.534	833.534	574.714	574.714	574.714	574.714	0.000	0.000
11:25	0.860	0.943	2733.807	2996.478	0.000	1642.691	3285.382	Disch1	Disch1	835.966	835.966	835.966	573.295	573.295	573.295	573.295	0.000	0.000
11:30	0.860	0.944	2732.389	2998.910	0.000	1641.831	3283.661	Disch1	Disch1	838.398	838.398	838.398	571.876	571.876	571.876	571.876	0.000	0.000
11:35	0.860	0.942	2734.667	2993.624	0.000	1640.970	3281.941	Disch1	Disch1	833.111	833.111	833.111	574.155	574.155	574.155	574.155	0.000	0.000
11:40	0.861	0.940	2736.946	2988.337	0.000	1640.110	3280.220	Disch1	Disch1	827.825	827.825	827.825	576.434	576.434	576.434	576.434	0.000	0.000
11:45	0.862	0.939	2739.225	2983.050	0.000	1639.250	3278.500	Disch1	Disch1	822.538	822.538	822.538	578.713	578.713	578.713	578.713	0.000	0.000
11:50	0.862	0.937	2741.504	2977.764	0.000	1638.390	3276.779	Disch1	Disch1	817.251	817.251	817.251	580.992	580.992	580.992	580.992	0.000	0.000
11:55	0.863	0.935	2743.783	2972.477	0.000	1637.529	3275.059	Disch1	Disch1	811.965	811.965	811.965	583.271	583.271	583.271	583.271	0.000	0.000
12:00	0.864	0.934	2746.062	2967.190	0.000	1636.669	3273.338	Disch1	Disch1	806.678	806.678	806.678	585.549	585.549	585.549	585.549	0.000	0.000
12:05	0.864	0.936	2745.068	2973.298	0.000	1631.995	3263.989	Disch1	Disch1	812.786	812.786	812.786	584.556	584.556	584.556	584.556	0.000	0.000
12:10	0.863	0.938	2744.075	2979.406	0.000	1627.320	3254.640	Disch1	Disch1	818.894	818.894	818.894	583.563	583.563	583.563	583.563	0.000	0.000
12:15	0.863	0.939	2743.081	2985.514	0.000	1622.646	3245.291	Disch1	Disch1	825.001	825.001	825.001	582.569	582.569	582.569	582.569	0.000	0.000
12:20	0.863	0.941	2742.088	2991.621	0.000	1617.971	3235.942	Disch1	Disch1	831.109	831.109	831.109	581.576	581.576	581.576	581.576	0.000	0.000
12:25	0.862	0.943	2741.094	2997.729	0.000	1613.297	3226.593	Disch1	Disch1	837.217	837.217	837.217	580.582	580.582	580.582	580.582	0.000	0.000

Figure A.7. Calculation tables (06:15 to 12:25 - Part 1/3).

	3			4			5			6			7			8		
	ES & PV (ES Arbitrage Used)			PV Surplus (Avail. for ES use)			ES profile including PV recharg			PV Surplus (For Rem. use)			ES Spare profile			PV Surplus (All ES Charged)		
Time	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com	5	10
06:15	0.000	0.000	0.000	0.000	0.000	-4.278	0.000	0.000	0.000	0.000	0.000	-4.278	0.000	0.000	0.000	0.000	0.000	-4.278
06:20	0.000	0.000	0.000	0.000	0.000	-4.090	0.000	0.000	0.000	0.000	0.000	-4.090	0.000	0.000	0.000	0.000	0.000	-4.090
06:25	0.000	0.000	0.000	0.000	0.000	-3.903	0.000	0.000	0.000	0.000	0.000	-3.903	0.000	0.000	0.000	0.000	0.000	-3.903
06:30	0.000	0.000	0.000	0.000	0.000	-3.715	0.000	0.000	0.000	0.000	0.000	-3.715	0.000	0.000	0.000	0.000	0.000	-3.715
06:35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
06:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:00	438.248	438.248	438.248	0.000	0.000	0.000	438.248	438.248	438.248	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:05	876.496	876.496	650.157	0.000	0.000	0.000	876.496	876.496	650.157	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:10	1314.744	1314.744	644.894	0.000	0.000	0.000	1314.744	1314.744	644.894	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:15	1752.993	1493.518	639.631	0.000	0.000	0.000	1752.993	1493.518	639.631	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:20	2191.241	1522.179	634.369	0.000	0.000	0.000	2191.241	1522.179	634.369	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:25	2191.241	1550.841	629.106	0.000	0.000	0.000	2191.241	1550.841	629.106	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:30	2191.241	1579.502	623.843	0.000	0.000	0.000	2191.241	1579.502	623.843	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:35	2191.241	1570.096	580.513	0.000	0.000	0.000	2191.241	1570.096	580.513	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:40	2191.241	1560.690	537.184	0.000	0.000	0.000	2191.241	1560.690	537.184	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:45	2191.241	1551.284	493.854	0.000	0.000	0.000	2191.241	1551.284	493.854	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:50	2191.241	1541.878	450.524	0.000	0.000	0.000	2191.241	1541.878	450.524	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
07:55	2191.241	1532.472	407.194	0.000	0.000	0.000	2191.241	1532.472	407.194	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:00	2191.241	1523.066	363.864	0.000	0.000	0.000	2191.241	1523.066	363.864	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:05	2191.241	1513.129	329.930	0.000	0.000	0.000	2191.241	1513.129	329.930	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:10	2191.241	1503.191	295.997	0.000	0.000	0.000	2191.241	1503.191	295.997	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:15	2191.241	1493.253	262.064	0.000	0.000	0.000	2191.241	1493.253	262.064	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:20	2191.241	1483.315	228.130	0.000	0.000	0.000	2191.241	1483.315	228.130	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:25	2191.241	1473.377	194.197	0.000	0.000	0.000	2191.241	1473.377	194.197	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:30	2191.241	1463.439	160.264	0.000	0.000	0.000	2191.241	1463.439	160.264	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:35	2191.241	1439.922	112.751	0.000	0.000	0.000	2191.241	1439.922	112.751	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:40	1519.010	1416.406	65.239	0.000	0.000	0.000	1519.010	1416.406	65.239	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:45	607.539	1392.889	17.726	0.000	0.000	0.000	607.539	1392.889	17.726	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:50	608.017	1369.372	0.000	0.000	0.000	-29.786	608.017	1369.372	-25.318	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
08:55	608.496	1345.855	0.000	0.000	0.000	-77.298	608.496	1345.855	-65.704	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:00	608.974	1322.338	0.000	0.000	0.000	-124.811	608.974	1322.338	-106.089	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:05	609.214	1309.674	0.000	0.000	0.000	-150.378	609.214	1309.674	-127.821	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:10	609.454	1297.010	0.000	0.000	0.000	-175.945	609.454	1297.010	-149.554	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:15	609.693	1284.346	0.000	0.000	0.000	-201.513	609.693	1284.346	-171.286	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:20	609.933	1271.682	0.000	0.000	0.000	-227.080	609.933	1271.682	-193.018	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:25	610.173	1259.019	0.000	0.000	0.000	-252.648	610.173	1259.019	-214.751	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:30	610.412	1246.355	0.000	0.000	0.000	-278.215	610.412	1246.355	-236.483	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:35	607.060	1228.423	0.000	0.000	0.000	-309.050	607.060	1228.423	-262.693	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:40	600.356	790.175	0.000	0.000	0.000	-339.885	600.356	790.175	-288.902	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:45	595.329	351.927	0.000	0.000	0.000	-370.720	595.329	351.927	-315.112	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:50	590.301	0.000	0.000	0.000	0.000	-401.555	590.301	0.000	-341.322	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
09:55	585.273	0.000	0.000	0.000	0.000	-432.390	585.273	0.000	-367.531	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:00	580.245	0.000	0.000	0.000	0.000	-463.225	580.245	0.000	-393.741	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:05	580.847	0.000	0.000	0.000	0.000	-470.123	580.847	0.000	-399.604	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:10	581.449	0.000	0.000	0.000	0.000	-477.021	581.449	0.000	-405.468	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:15	582.051	0.000	0.000	0.000	0.000	-483.919	582.051	0.000	-411.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:20	582.653	0.000	0.000	0.000	0.000	-490.818	582.653	0.000	-417.195	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:25	583.255	0.000	0.000	0.000	0.000	-497.716	583.255	0.000	-423.059	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:30	583.857	0.000	0.000	0.000	0.000	-504.614	583.857	0.000	-428.922	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:35	583.279	0.000	0.000	0.000	0.000	-512.692	583.279	0.000	-435.788	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:40	582.701	0.000	0.000	0.000	0.000	-520.770	582.701	0.000	-442.655	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:45	582.123	0.000	0.000	0.000	0.000	-528.848	582.123	0.000	-449.521	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:50	581.545	0.000	0.000	0.000	0.000	-536.926	581.545	0.000	-456.388	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:55	580.967	0.000	0.000	0.000	0.000	-545.005	580.967	0.000	-463.254	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11:00	580.389	0.000	0.000	0.000	0.000	-553.083	580.389	0.000	-470.120	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11:05	578.970	0.000	0.000	0.000	0.000	-552.781	578.970	0.000	-297.049	0.000	0.000	-203.312	0.000	0.000	0.000	0.000	0.000	-203.312
11:10	577.552	0.000	0.000	0.000	0.000	-552.479	577.552	0.000	0.000	0.000	0.000	-552.479	0.000	0.000	0.000	0.000	0.000	-552.479
11:15	576.133	0.000	0.000	0.000	0.000	-552.178	576.133	0.000	0.000	0.000	0.000	-552.178	0.000	0.000	0.000	0.000	0.000	-552.178
11:20	574.714	0.000	0.000	0.000	0.000	-551.876	574.714	0.000	0.000	0.000	0.000	-551.876	0.000	0.000	0.000	0.000	0.000	-551.876
11:25	573.295	0.000	0.000	0.000	0.000	-551.574	573.295	0.000	0.000	0.000	0.000	-551.574	0.000	0.000	0.000	0.000	0.000	-551.574
11:30	571.876	0.000	0.000	0.000	0.000	-551.273	571.876	0.000	0.000	0.000	0.000	-551.273	0.000	0.000	0.000	0.000	0.000	-551.273
11:35	574.155	0.000	0.000	0.000	0.000	-547.273	574.155	0.000	0.000	0.000	0.000	-547.273	0.000	0.000	0.000	0.000	0.000	-547.273
11:40	576.434	0.000	0.000	0.000	0.000	-543.274	576.434	0.000	0.000	0.000	0.000	-543.274	0.000	0.000	0.000	0.000	0.000	-543.274
11:45	578.713	0.000	0.000	0.000	0.000	-539.275	578.713	0.000	0.000	0.000	0.000	-539.275	0.000	0.000	0.000	0.000	0.000	-539.275
11:50	580.992	0.000	0.000	0.000	0.000	-535.275	580.992	0.000	0.000	0.000	0.000	-535.275	0.000	0.000	0.000	0.000	0.000	-535.275
11:55	583.271	0.000	0.000	0.000	0.000	-531.276	583.271	0.000	0.000	0.000	0.000	-531.276	0.000	0.000	0.000	0.000	0.000	-531.276
12:00	585.549	0.000	0.000	0.000	0.000	-527.277	585.549	0.000	0.000	0.000	0.000	-527.277	0.000	0.000	0.000	0.000	0.000	-527.277
12:05	584.556	0.000	0.000	0.000	0.000	-518.921	584.556	0.000	0.000	0.000	0.000	-518.921	0.000	0.000	0.000	0.000	0.000	-518.921
12:10	583.563	0.000	0.000	0.000	0.000	-510.565	583.563	0.000	0.000	0.000	0.000	-510.565	0.000	0.000	0.000	0.000	0.000	-510.565
12:15	582.569	0.000	0.000	0.000	0.000	-502.210	582.569	0.000	0.000	0.000	0.000	-502.210	0.000	0.000	0.000	0.000	0.000	-502.210
12:20	581.576	0.000	0.000	0.000	0.000	-493.854	581.576	0.000	0.000	0.000	0.000	-493.854	0.000	0.000	0.000	0.000	0.000	-493.854
12:25	580.582	0.000	0.000	0.000	0.000	-485.499	580.582	0.000	0.000	0.000	0.000	-485.499	0.000	0.000	0.000	0.000	0.000	-485.499

Figure A.8. Calculation tables (06:15 to 12:25 - Part 2/3).

	9															
	ES to be recharged by grid			ES Profiles Clip (ES Calc)			ES Capacity Profile			BESS Maximim PRR			After DR Demand (at POC)			Tariff
Time	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com (Var)	5	10	Select 3
06:15	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%				780.069	387.896	-4.278	S
06:20	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%				860.243	428.077	-4.090	S
06:25	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%				940.418	468.258	-3.903	S
06:30	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%				1020.592	508.439	-3.715	S
06:35	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%				1210.435	658.288	106.141	S
06:40	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%				1400.278	808.137	215.996	S
06:45	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%				1590.120	957.986	325.852	S
06:50	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%				1779.963	1107.835	435.708	S
06:55	0.000	0.000	0.000	0.000	0.000	0.000	100%	100%	100%				1969.806	1257.685	545.564	S
07:00	438.248	438.248	438.248	438.248	438.248	438.248	100%	100%	100%	20%	20%	20%	1721.400	969.286	217.171	S
07:05	876.496	876.496	650.157	876.496	876.496	650.157	99%	99%	99%	20%	20%	10%	1345.737	559.699	0.000	S
07:10	1314.744	1314.744	644.894	1314.744	1314.744	644.894	98%	98%	98%	20%	20%	0%	970.075	150.112	0.000	S
07:15	1752.993	1493.518	639.631	1752.993	1493.518	639.631	96%	96%	98%	20%	8%	0%	594.412	0.000	0.000	S
07:20	2191.241	1522.179	634.369	2191.241	1522.179	634.369	94%	95%	97%	20%	1%	0%	218.749	0.000	0.000	S
07:25	2191.241	1550.841	629.106	2191.241	1550.841	629.106	92%	93%	97%		1%	0%	281.335	0.000	0.000	S
07:30	2191.241	1579.502	623.843	2191.241	1579.502	623.843	90%	92%	96%		1%	0%	343.920	0.000	0.000	P
07:35	2191.241	1570.096	580.513	2191.241	1570.096	580.513	88%	90%	95%		0%	2%	368.438	0.000	0.000	P
07:40	2191.241	1560.690	537.184	2191.241	1560.690	537.184	85%	89%	95%		0%	2%	392.956	0.000	0.000	P
07:45	2191.241	1551.284	493.854	2191.241	1551.284	493.854	83%	87%	94%		0%	2%	417.474	0.000	0.000	P
07:50	2191.241	1541.878	450.524	2191.241	1541.878	450.524	81%	86%	94%		0%	2%	441.992	0.000	0.000	P
07:55	2191.241	1532.472	407.194	2191.241	1532.472	407.194	79%	84%	94%		0%	2%	466.510	0.000	0.000	P
08:00	2191.241	1523.066	363.864	2191.241	1523.066	363.864	77%	83%	93%		0%	2%	491.028	0.000	0.000	P
08:05	2191.241	1513.129	329.930	2191.241	1513.129	329.930	75%	81%	93%		0%	2%	505.086	0.000	0.000	P
08:10	2191.241	1503.191	295.997	2191.241	1503.191	295.997	73%	80%	93%		0%	2%	519.144	0.000	0.000	P
08:15	2191.241	1493.253	262.064	2191.241	1493.253	262.064	71%	79%	92%		0%	2%	533.201	0.000	0.000	P
08:20	2191.241	1483.315	228.130	2191.241	1483.315	228.130	69%	77%	92%		0%	2%	547.259	0.000	0.000	P
08:25	2191.241	1473.377	194.197	2191.241	1473.377	194.197	67%	76%	92%		0%	2%	561.317	0.000	0.000	P
08:30	2191.241	1463.439	160.264	2191.241	1463.439	160.264	65%	74%	92%		0%	2%	575.374	0.000	0.000	P
08:35	2191.241	1439.922	112.751	2191.241	1439.922	112.751	63%	73%	92%		1%	2%	575.853	0.000	0.000	P
08:40	1519.010	1416.406	65.239	1519.010	1416.406	65.239	61%	72%	92%	31%	1%	2%	1248.562	0.000	0.000	P
08:45	607.539	1392.889	17.726	607.539	1392.889	17.726	60%	70%	92%	42%	1%	2%	2160.512	0.000	0.000	P
08:50	608.017	1369.372	-25.318	608.017	1369.372	-25.318	60%	69%	92%	0%	1%	2%	2160.512	0.000	0.000	P
08:55	608.496	1345.855	-65.704	608.496	1345.855	-65.704	59%	68%	92%	0%	1%	2%	2160.512	0.000	0.000	P
09:00	608.974	1322.338	-106.089	608.974	1322.338	-106.089	59%	66%	92%	0%	1%	2%	2160.512	0.000	0.000	P
09:05	609.214	1309.674	-127.821	609.214	1309.674	-127.821	58%	65%	92%	0%	1%	1%	2160.512	0.000	0.000	P
09:10	609.454	1297.010	-149.554	609.454	1297.010	-149.554	58%	64%	92%	0%	1%	1%	2160.512	0.000	0.000	P
09:15	609.693	1284.346	-171.286	609.693	1284.346	-171.286	57%	63%	92%	0%	1%	1%	2160.512	0.000	0.000	P
09:20	609.933	1271.682	-193.018	609.933	1271.682	-193.018	56%	62%	92%	0%	1%	1%	2160.512	0.000	0.000	P
09:25	610.173	1259.019	-214.751	610.173	1259.019	-214.751	56%	60%	93%	0%	1%	1%	2160.512	0.000	0.000	P
09:30	610.412	1246.355	-236.483	610.412	1246.355	-236.483	55%	59%	93%	0%	1%	1%	2160.512	0.000	0.000	P
09:35	607.060	1228.423	-262.693	607.060	1228.423	-262.693	55%	58%	93%	0%	1%	1%	2158.837	0.000	0.000	P
09:40	600.356	790.175	-288.902	600.356	790.175	-288.902	54%	57%	93%	0%	20%	1%	2160.512	420.317	0.000	P
09:45	595.329	351.927	-315.112	595.329	351.927	-315.112	54%	57%	94%	0%	20%	1%	2160.512	840.634	0.000	P
09:50	590.301	0.000	-341.322	590.301	0.000	-341.322	53%	57%	94%	0%	16%	1%	2160.512	1174.629	0.000	P
09:55	585.273	0.000	-367.531	585.273	0.000	-367.531	52%	57%	94%	0%		1%	2160.512	1156.698	0.000	P
10:00	580.245	0.000	-393.741	580.245	0.000	-393.741	52%	57%	95%	0%		1%	2160.512	1138.766	0.000	P
10:05	580.847	0.000	-399.604	580.847	0.000	-399.604	51%	57%	95%	0%		0%	2160.512	1135.618	0.000	P
10:10	581.449	0.000	-405.468	581.449	0.000	-405.468	51%	57%	96%	0%		0%	2160.512	1132.470	0.000	P
10:15	582.051	0.000	-411.331	582.051	0.000	-411.331	50%	57%	96%	0%		0%	2160.512	1129.322	0.000	P
10:20	582.653	0.000	-417.195	582.653	0.000	-417.195	50%	57%	96%	0%		0%	2160.512	1126.174	0.000	P
10:25	583.255	0.000	-423.059	583.255	0.000	-423.059	49%	57%	97%	0%		0%	2160.512	1123.025	0.000	P
10:30	583.857	0.000	-428.922	583.857	0.000	-428.922	49%	57%	97%	0%		0%	2160.512	1119.877	0.000	S
10:35	583.279	0.000	-435.788	583.279	0.000	-435.788	48%	57%	98%	0%		0%	2160.512	1115.549	0.000	S
10:40	582.701	0.000	-442.655	582.701	0.000	-442.655	47%	57%	98%	0%		0%	2160.512	1111.221	0.000	S
10:45	582.123	0.000	-449.521	582.123	0.000	-449.521	47%	57%	98%	0%		0%	2160.512	1106.893	0.000	S
10:50	581.545	0.000	-456.388	581.545	0.000	-456.388	46%	57%	99%	0%		0%	2160.512	1102.565	0.000	S
10:55	580.967	0.000	-463.254	580.967	0.000	-463.254	46%	57%	99%	0%		0%	2160.512	1098.237	0.000	S
11:00	580.389	0.000	-470.120	580.389	0.000	-470.120	45%	57%	100%	0%		0%	2160.512	1093.909	0.000	S
11:05	578.970	0.000	-297.049	578.970	0.000	-297.049	45%	57%	100%	0%		8%	2160.512	1093.351	-203.312	S
11:10	577.552	0.000	0.000	577.552	0.000	0.000	44%	57%	100%	0%		14%	2160.512	1092.792	-552.479	S
11:15	576.133	0.000	0.000	576.133	0.000	0.000	44%	57%	100%	0%			2160.512	1092.234	-552.178	S
11:20	574.714	0.000	0.000	574.714	0.000	0.000	43%	57%	100%	0%			2160.512	1091.675	-551.876	S
11:25	573.295	0.000	0.000	573.295	0.000	0.000	43%	57%	100%	0%			2160.512	1091.117	-551.574	S
11:30	571.876	0.000	0.000	571.876	0.000	0.000	42%	57%	100%	0%			2160.512	1090.558	-551.273	S
11:35	574.155	0.000	0.000	574.155	0.000	0.000	41%	57%	100%	0%			2160.512	1093.697	-547.273	S
11:40	576.434	0.000	0.000	576.434	0.000	0.000	41%	57%	100%	0%			2160.512	1096.836	-543.274	S
11:45	578.713	0.000	0.000	578.713	0.000	0.000	40%	57%	100%	0%			2160.512	1099.975	-539.275	S
11:50	580.992	0.000	0.000	580.992	0.000	0.000	40%	57%	100%	0%			2160.512	1103.114	-535.275	S
11:55	583.271	0.000	0.000	583.271	0.000	0.000	39%	57%	100%	0%			2160.512	1106.253	-531.276	S
12:00	585.549	0.000	0.000	585.549	0.000	0.000	39%	57%	100%	0%			2160.512	1109.393	-527.277	S
12:05	584.556	0.000	0.000	584.556	0.000	0.000	38%	57%	100%	0%			2160.512	1113.074	-518.921	S
12:10	583.563	0.000	0.000	583.563	0.000	0.000	38%	57%	100%	0%			2160.512	1116.755	-510.565	S
12:15	582.569	0.000	0.000	582.569	0.000	0.000	37%	57%	100%	0%			2160.512	1120.436	-502.210	S
12:20	581.576	0.000	0.000	581.576	0.000	0.000	36%	57%	100%	0%			2160.512	1124.117	-493.854	S
12:25	580.582	0.000	0.000	580.582	0.000	0.000	36%	57%	100%	0%			2160.512	1127.798	-485.499	S

Figure A.9. Calculation tables (06:15 to 12:25 - Part 3/3).

										0			1			2		
	Low	Weekday	Load Demand		Calculated PV Profiles			ES State	ES State	ES System Ratings (No PV)			ES System Reserve (No PV)			ES & PV Ops (No Surplus Used)		
Time	Norm. data (pu)		Real, incl. MSS		Com	5	10	Rating	Ops.	Com	5	10	Com	5	10	Com	5	10
	Ops:	ES Rating:	Ops:	ES Rating:						68%	68%	68%						
12:30	0.862	0.945	2740.101	3003.837	0.000	1608.622	3217.244	Disch1	Disch1	843.324	843.324	843.324	579.589	579.589	579.589	579.589	0.000	0.000
12:35	0.863	0.944	2743.821	2998.623	0.000	1603.947	3207.895	Disch1	Disch1	838.111	838.111	838.111	583.308	583.308	583.308	583.308	0.000	0.000
12:40	0.864	0.942	2747.540	2993.410	0.000	1599.273	3198.546	Disch1	Disch1	832.898	832.898	832.898	587.028	587.028	587.028	587.028	0.000	0.000
12:45	0.866	0.940	2751.260	2988.197	0.000	1594.598	3189.197	Disch1	Disch1	827.685	827.685	827.685	590.748	590.748	590.748	590.748	0.000	0.000
12:50	0.867	0.939	2754.980	2982.984	0.000	1589.924	3179.848	Disch1	Disch1	822.472	822.472	822.472	594.467	594.467	594.467	594.467	0.000	0.000
12:55	0.868	0.937	2758.699	2977.771	0.000	1585.249	3170.498	Disch1	Disch1	817.259	817.259	817.259	598.187	598.187	598.187	598.187	0.000	0.000
13:00	0.869	0.935	2762.419	2972.558	0.000	1580.575	3161.149	Disch1	Disch1	812.045	812.045	812.045	601.907	601.907	601.907	601.907	0.000	0.000
13:05	0.869	0.936	2760.950	2975.249	0.000	1569.713	3139.425	Disch1	Disch1	814.736	814.736	814.736	600.438	600.438	600.438	600.438	0.000	0.000
13:10	0.868	0.937	2759.481	2977.939	0.000	1558.851	3117.702	Disch1	Disch1	817.427	817.427	817.427	598.969	598.969	598.969	598.969	0.000	0.000
13:15	0.868	0.938	2758.012	2980.630	0.000	1547.989	3095.978	Disch1	Disch1	820.118	820.118	820.118	597.500	597.500	597.500	597.500	0.000	0.000
13:20	0.867	0.939	2756.543	2983.321	0.000	1537.127	3074.254	Disch1	Disch1	822.809	822.809	822.809	596.031	596.031	596.031	596.031	0.000	0.000
13:25	0.867	0.940	2755.074	2986.012	0.000	1526.265	3052.530	Disch1	Disch1	825.500	825.500	825.500	594.561	594.561	594.561	594.561	0.000	0.000
13:30	0.866	0.940	2753.605	2988.703	0.000	1515.403	3030.806	Disch1	Disch1	828.191	828.191	828.191	593.092	593.092	593.092	593.092	0.000	0.000
13:35	0.866	0.937	2752.076	2977.107	0.000	1504.541	3009.082	Disch1	Disch1	816.595	816.595	816.595	591.563	591.563	591.563	591.563	0.000	0.000
13:40	0.865	0.933	2750.546	2965.512	0.000	1493.679	2987.358	Disch1	Disch1	805.000	805.000	805.000	590.034	590.034	590.034	590.034	0.000	0.000
13:45	0.865	0.929	2749.017	2953.917	0.000	1482.817	2965.634	Disch1	Disch1	793.404	793.404	793.404	588.505	588.505	588.505	588.505	0.000	0.000
13:50	0.864	0.926	2747.488	2942.321	0.000	1471.955	2943.910	Disch1	Disch1	781.809	781.809	781.809	586.976	586.976	586.976	586.976	0.000	0.000
13:55	0.864	0.922	2745.959	2930.726	0.000	1461.093	2922.186	Disch1	Disch1	770.213	770.213	770.213	585.446	585.446	585.446	585.446	0.000	0.000
14:00	0.863	0.919	2744.430	2919.130	0.000	1450.231	2900.462	Disch1	Disch1	758.618	758.618	758.618	583.917	583.917	583.917	583.917	0.000	0.000
14:05	0.864	0.919	2745.065	2921.421	0.000	1429.282	2858.565	Disch1	Disch1	760.908	760.908	760.908	584.553	584.553	584.553	584.553	0.000	0.000
14:10	0.864	0.920	2745.701	2923.711	0.000	1408.334	2816.667	Disch1	Disch1	763.199	763.199	763.199	585.188	585.188	585.188	585.188	0.000	0.000
14:15	0.864	0.921	2746.336	2926.002	0.000	1387.385	2774.769	Disch1	Disch1	765.489	765.489	765.489	585.824	585.824	585.824	585.824	0.000	0.000
14:20	0.864	0.921	2746.972	2928.292	0.000	1366.436	2732.872	Disch1	Disch1	767.780	767.780	767.780	586.460	586.460	586.460	586.460	0.000	0.000
14:25	0.864	0.922	2747.607	2930.583	0.000	1345.487	2690.974	Disch1	Disch1	770.070	770.070	770.070	587.095	587.095	587.095	587.095	0.000	0.000
14:30	0.865	0.923	2748.243	2932.873	0.000	1324.538	2649.076	Disch1	Disch1	772.361	772.361	772.361	587.731	587.731	587.731	587.731	0.000	0.000
14:35	0.862	0.922	2738.786	2928.595	0.000	1303.589	2607.179	Disch1	Disch1	768.082	768.082	768.082	578.273	578.273	578.273	578.273	0.000	0.000
14:40	0.859	0.920	2729.328	2924.316	0.000	1282.641	2565.281	Disch1	Disch1	763.804	763.804	763.804	568.816	568.816	568.816	568.816	0.000	0.000
14:45	0.856	0.919	2719.871	2920.038	0.000	1261.692	2523.384	Disch1	Disch1	759.526	759.526	759.526	559.358	559.358	559.358	559.358	0.000	0.000
14:50	0.853	0.917	2710.413	2915.760	0.000	1240.743	2481.486	Disch1	Disch1	755.247	755.247	755.247	549.901	549.901	549.901	549.901	0.000	0.000
14:55	0.850	0.916	2700.956	2911.481	0.000	1219.794	2439.588	Disch1	Disch1	750.969	750.969	750.969	540.444	540.444	540.444	540.444	0.000	0.000
15:00	0.847	0.915	2691.498	2907.203	0.000	1198.845	2397.691	Disch1	Disch1	746.691	746.691	746.691	530.986	530.986	530.986	530.986	0.000	0.000
15:05	0.846	0.913	2690.980	2901.935	0.000	1169.544	2339.087	Disch1	Disch1	741.423	741.423	741.423	530.468	530.468	530.468	530.468	0.000	0.000
15:10	0.846	0.911	2690.462	2896.667	0.000	1140.242	2280.484	Disch1	Disch1	736.155	736.155	736.155	529.950	529.950	529.950	529.950	0.000	0.000
15:15	0.846	0.910	2689.944	2891.399	0.000	1110.940	2221.880	Disch1	Disch1	730.887	730.887	730.887	529.432	529.432	529.432	529.432	0.000	0.000
15:20	0.846	0.908	2689.426	2886.131	0.000	1081.638	2163.277	Disch1	Disch1	725.619	725.619	725.619	528.914	528.914	528.914	528.914	0.000	0.000
15:25	0.846	0.906	2688.908	2880.864	0.000	1052.337	2104.673	Disch1	Disch1	720.351	720.351	720.351	528.396	528.396	528.396	528.396	0.000	0.000
15:30	0.846	0.905	2688.390	2875.596	0.000	1023.035	2046.069	Disch1	Disch1	715.083	715.083	715.083	527.878	527.878	527.878	527.878	0.000	0.000
15:35	0.845	0.903	2685.109	2870.245	0.000	993.733	1987.466	Disch1	Disch1	709.733	709.733	709.733	524.597	524.597	524.597	524.597	0.000	0.000
15:40	0.844	0.901	2681.828	2864.895	0.000	964.431	1928.862	Disch1	Disch1	704.383	704.383	704.383	521.315	521.315	521.315	521.315	0.000	0.000
15:45	0.843	0.900	2678.546	2859.545	0.000	935.129	1870.259	Disch1	Disch1	699.033	699.033	699.033	518.034	518.034	518.034	518.034	0.000	0.000
15:50	0.842	0.898	2675.265	2854.195	0.000	905.828	1811.655	Disch1	Disch1	693.682	693.682	693.682	514.753	514.753	514.753	514.753	0.000	0.000
15:55	0.840	0.896	2671.984	2848.844	0.000	876.526	1753.052	Disch1	Disch1	688.332	688.332	688.332	511.471	511.471	511.471	511.471	0.000	0.000
16:00	0.839	0.895	2668.702	2843.494	0.000	847.224	1694.448	Disch1	Disch1	682.982	682.982	682.982	508.190	508.190	508.190	508.190	0.000	0.000
16:05	0.838	0.892	2663.076	2835.289	0.000	810.855	1621.711	Disch1	Disch1	674.777	674.777	674.777	502.563	502.563	502.563	502.563	0.000	0.000
16:10	0.836	0.889	2657.449	2827.084	0.000	774.487	1548.973	Disch1	Disch1	666.572	666.572	666.572	496.937	496.937	496.937	496.937	0.000	0.000
16:15	0.834	0.887	2651.822	2818.880	0.000	738.118	1476.235	Disch1	Disch1	658.367	658.367	658.367	491.310	491.310	491.310	491.310	0.000	0.000
16:20	0.832	0.884	2646.195	2810.675	0.000	701.749	1403.498	Disch1	Disch1	650.162	650.162	650.162	485.683	485.683	485.683	485.683	0.000	0.000
16:25	0.831	0.882	2640.569	2802.470	0.000	665.380	1330.760	Disch1	Disch1	641.958	641.958	641.958	480.056	480.056	480.056	480.056	0.000	0.000
16:30	0.829	0.879	2634.942	2794.265	0.000	629.011	1258.022	Disch1	Disch1	633.753	633.753	633.753	474.430	474.430	474.430	474.430	0.000	0.000
16:35	0.828	0.880	2632.834	2796.020	0.000	592.642	1185.285	Disch1	Disch1	635.508	635.508	635.508	472.322	472.322	472.322	472.322	0.000	0.000
16:40	0.827	0.880	2630.726	2797.776	0.000	556.274	1112.547	Disch1	Disch1	637.263	637.263	637.263	470.214	470.214	470.214	470.214	0.000	0.000
16:45	0.827	0.881	2628.618	2799.531	0.000	519.905	1039.809	Disch1	Disch1	639.019	639.019	639.019	468.105	468.105	468.105	468.105	0.000	0.000
16:50	0.826	0.881	2626.510	2801.286	0.000	483.536	967.072	Disch1	Disch1	640.774	640.774	640.774	465.997	465.997	465.997	465.997	0.000	0.000
16:55	0.825	0.882	2624.402	2803.042	0.000	447.167	894.334	Disch1	Disch1	642.529	642.529	642.529	463.889	463.889	463.889	463.889	16.722	0.000
17:00	0.825	0.882	2622.294	2804.797	0.000	410.798	821.596	Disch1	Disch1	644.285	644.285	644.285	461.781	461.781	461.781	461.781	50.983	0.000
17:05	0.826	0.883	2625.164	2805.375	0.000	381.749	763.498	Disch1	Disch1	644.863	644.863	644.863	464.652	464.652	464.652	464.652	82.903	0.000
17:10	0.827	0.883	2628.035	2805.953	0.000	352.700	705.399	Disch1	Disch1	645.441	645.441	645.441	467.523	467.523	467.523	467.523	114.823	0.000
17:15	0.828	0.883	2630.905	2806.531	0.000	323.651	647.301	Disch1	Disch1	646.019	646.019	646.019	470.393	470.393	470.393	470.393	146.743	0.000
17:20	0.828	0.883	2633.776	2807.109	0.000	294.601	589.203	Disch1	Disch1	646.597	646.597	646.597	473.264	473.264	473.264	473.264	178.662	0.000
17:25	0.829	0.883	2636.647	2807.687	0.000	265.552	531.104	Disch1	Disch1	647.175	647.175	647.175	476.134	476.134	476.134	476.134	210.582	0.000
17:30	0.830	0.884	2639.517	2808.265	0.000	236.503	473.006	Disch1	Disch1	647.753	647.753	647.753	479.005	479.005	479.005	479.005	242.502	5.999
17:35	0.826	0.872	2625.689	2770.264	0.000	207.454	414.907	Disch1	Disch1	609.752	609.752	609.752	465.176	465.176	465.176	465.176	257.723	50.269
17:40	0.821	0.860	2611.860	2732.263	0.000	178.404	356.809	Disch1	Disch1	571.751	571.751	571.751	451.348	451.348	451.348	451.348	272.943	94.539
17:45	0.817	0.848	2598.031	2694.262	0.000	149.355	298.710	Disch1	Disch1	533.750	533.750	533.750	437.519	437.519	437.519	437.519	288.164	138.809
17:50	0.813	0.836	2584.203	2656.261	0.000	120.306	240.612	Disch1	Disch1	495.748	495.748	495.748	423.690	423.690	423.690	423.690	303.384	183.078
17:55	0.808	0.824	2570.374	2618.260	0.000	91.257	182.514	Disch1	Disch1	457.747	457.747	457.747	409.862	409.862	409.862	409.862	318.605	227.348
18:00	0.804	0.812	2556.545	2580.258	0.000	62.208	124.415	Disch1	Disch1	419.746	419.746	419.746	396.033	396.033	396.033	396.033	333.826	271.618
18:05	0.791	0.785	2514.041	2497.713	0.000	57.021	114.041	Disch1	Disch1	337.201	337.201	337.201	353.529	353.529	353.529	353.529	296.508	239.487
18:10	0.777	0.759	2471.536	2415.168	0.000	51.834	103.667	Disch1	Disch1	254.656	254.656	254.656	311.024	311.024	311.024	311.024	259.190	207.357
18:15	0.764	0.733	2429.032	2332.623	0.000	46.647	93.293	Disch1	Disch1	172.111	172.111	172.111	268.519	268.519	268.519	268.519	221.873	175.226
18:20	0.750	0.707	2386.527	2250.078	0.000	41.460	82.920	Disch1	Disch1	89.566	89.566	89.566	226.015	226.015	226.015	226.015	184.555	143.095
18:25	0.737	0.681	2344.022	2167.533	0.000	36.273	72.546	Disch1	Disch1	7.021	7.021	7.021	183.510	183.510	183.510	183.510	147.237	110.965
18:30	0.724	0.655	2301.518	2084.988	0.000	31.086	62.172	Disch1	Disch1	0.000	0.000	0.000	141.006	141.006	141.006	141.006	109.920	78.834
18:35	0.709	0.630	2254.503	2004.805	0.000	25.905	51.810	Disch1	Disch1	0.000	0.000	0.000	93.991	93.991	93.991	93.991	68.086	42.181
18:40	0.694	0.605	2207.488	1924.623	0.000	20.724	41.448	Disch1	Disch1	0.000	0.000	0.000	46.976	46.976	46.976	46.976	26.252	5.528

Figure A.10. Calculation tables (12:30 to 18:40 - Part 1/3).

	3			4			5			6			7			8		
	ES & PV (ES Arbitrage Used)			PV Surplus (Avail. for ES use)			ES profile including PV recharg			PV Surplus (For Rem. use)			ES Spare profile			PV Surplus (All ES Charged)		
Time	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com	5	10
12:30	579.589	0.000	0.000	0.000	0.000	-477.143	579.589	0.000	0.000	0.000	0.000	-477.143	0.000	0.000	0.000	0.000	0.000	-477.143
12:35	583.308	0.000	0.000	0.000	0.000	-464.074	583.308	0.000	0.000	0.000	0.000	-464.074	0.000	0.000	0.000	0.000	0.000	-464.074
12:40	587.028	0.000	0.000	0.000	0.000	-451.006	587.028	0.000	0.000	0.000	0.000	-451.006	0.000	0.000	0.000	0.000	0.000	-451.006
12:45	590.748	0.000	0.000	0.000	0.000	-437.937	590.748	0.000	0.000	0.000	0.000	-437.937	0.000	0.000	0.000	0.000	0.000	-437.937
12:50	594.467	0.000	0.000	0.000	0.000	-424.868	594.467	0.000	0.000	0.000	0.000	-424.868	0.000	0.000	0.000	0.000	0.000	-424.868
12:55	598.187	0.000	0.000	0.000	0.000	-411.799	598.187	0.000	0.000	0.000	0.000	-411.799	0.000	0.000	0.000	0.000	0.000	-411.799
13:00	601.907	0.000	0.000	0.000	0.000	-398.730	601.907	0.000	0.000	0.000	0.000	-398.730	0.000	0.000	0.000	0.000	0.000	-398.730
13:05	600.438	0.000	0.000	0.000	0.000	-378.476	600.438	0.000	0.000	0.000	0.000	-378.476	0.000	0.000	0.000	0.000	0.000	-378.476
13:10	598.969	0.000	0.000	0.000	0.000	-358.221	598.969	0.000	0.000	0.000	0.000	-358.221	0.000	0.000	0.000	0.000	0.000	-358.221
13:15	597.500	0.000	0.000	0.000	0.000	-337.966	597.500	0.000	0.000	0.000	0.000	-337.966	0.000	0.000	0.000	0.000	0.000	-337.966
13:20	596.031	0.000	0.000	0.000	0.000	-317.711	596.031	0.000	0.000	0.000	0.000	-317.711	0.000	0.000	0.000	0.000	0.000	-317.711
13:25	594.561	0.000	0.000	0.000	0.000	-297.456	594.561	0.000	0.000	0.000	0.000	-297.456	0.000	0.000	0.000	0.000	0.000	-297.456
13:30	593.092	0.000	0.000	0.000	0.000	-277.201	593.092	0.000	0.000	0.000	0.000	-277.201	0.000	0.000	0.000	0.000	0.000	-277.201
13:35	591.563	0.000	0.000	0.000	0.000	-257.006	591.563	0.000	0.000	0.000	0.000	-257.006	0.000	0.000	0.000	0.000	0.000	-257.006
13:40	590.034	0.000	0.000	0.000	0.000	-236.812	590.034	0.000	0.000	0.000	0.000	-236.812	0.000	0.000	0.000	0.000	0.000	-236.812
13:45	588.505	0.000	0.000	0.000	0.000	-216.617	588.505	0.000	0.000	0.000	0.000	-216.617	0.000	0.000	0.000	0.000	0.000	-216.617
13:50	586.976	0.000	0.000	0.000	0.000	-196.422	586.976	0.000	0.000	0.000	0.000	-196.422	0.000	0.000	0.000	0.000	0.000	-196.422
13:55	585.446	0.000	0.000	0.000	0.000	-176.227	585.446	0.000	0.000	0.000	0.000	-176.227	0.000	0.000	0.000	0.000	0.000	-176.227
14:00	583.917	0.000	0.000	0.000	0.000	-156.033	583.917	0.000	0.000	0.000	0.000	-156.033	0.000	0.000	0.000	0.000	0.000	-156.033
14:05	584.553	0.000	0.000	0.000	0.000	-113.500	584.553	0.000	0.000	0.000	0.000	-113.500	0.000	0.000	0.000	0.000	0.000	-113.500
14:10	585.188	0.000	0.000	0.000	0.000	-70.966	585.188	0.000	0.000	0.000	0.000	-70.966	0.000	0.000	0.000	0.000	0.000	-70.966
14:15	585.824	0.000	0.000	0.000	0.000	-28.433	585.824	0.000	0.000	0.000	0.000	-28.433	0.000	0.000	0.000	0.000	0.000	-28.433
14:20	586.460	0.000	0.000	0.000	0.000	0.000	586.460	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
14:25	587.095	0.000	0.000	0.000	0.000	0.000	587.095	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
14:30	587.731	0.000	0.000	0.000	0.000	0.000	587.731	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
14:35	578.273	0.000	0.000	0.000	0.000	0.000	578.273	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
14:40	568.816	0.000	0.000	0.000	0.000	0.000	568.816	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
14:45	559.358	0.000	0.000	0.000	0.000	0.000	559.358	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
14:50	549.901	0.000	0.000	0.000	0.000	0.000	549.901	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
14:55	540.444	0.000	0.000	0.000	0.000	0.000	540.444	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:00	530.986	0.000	0.000	0.000	0.000	0.000	530.986	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:05	530.468	0.000	0.000	0.000	0.000	0.000	530.468	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:10	529.950	0.000	0.000	0.000	0.000	0.000	529.950	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:15	529.432	0.000	0.000	0.000	0.000	0.000	529.432	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:20	528.914	0.000	0.000	0.000	0.000	0.000	528.914	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:25	528.396	0.000	0.000	0.000	0.000	0.000	528.396	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:30	527.878	0.000	0.000	0.000	0.000	0.000	527.878	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:35	524.597	0.000	0.000	0.000	0.000	0.000	524.597	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:40	521.315	0.000	0.000	0.000	0.000	0.000	521.315	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:45	518.034	0.000	0.000	0.000	0.000	0.000	518.034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:50	514.753	0.000	0.000	0.000	0.000	0.000	514.753	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15:55	511.471	0.000	0.000	0.000	0.000	0.000	511.471	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:00	508.190	0.000	0.000	0.000	0.000	0.000	508.190	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:05	502.563	0.000	0.000	0.000	0.000	0.000	502.563	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:10	496.937	0.000	0.000	0.000	0.000	0.000	496.937	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:15	491.310	0.000	0.000	0.000	0.000	0.000	491.310	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:20	485.683	0.000	0.000	0.000	0.000	0.000	485.683	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:25	480.056	0.000	0.000	0.000	0.000	0.000	480.056	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:30	474.430	0.000	0.000	0.000	0.000	0.000	474.430	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:35	472.322	0.000	0.000	0.000	0.000	0.000	472.322	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:40	470.214	0.000	0.000	0.000	0.000	0.000	470.214	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:45	468.105	0.000	0.000	0.000	0.000	0.000	468.105	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:50	465.997	0.000	0.000	0.000	0.000	0.000	465.997	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16:55	463.889	16.722	0.000	0.000	0.000	0.000	463.889	16.722	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:00	461.781	50.983	0.000	0.000	0.000	0.000	461.781	50.983	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:05	464.652	82.903	0.000	0.000	0.000	0.000	464.652	82.903	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:10	467.523	114.823	0.000	0.000	0.000	0.000	467.523	114.823	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:15	470.393	146.743	0.000	0.000	0.000	0.000	470.393	146.743	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:20	473.264	178.662	0.000	0.000	0.000	0.000	473.264	178.662	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:25	476.134	210.582	0.000	0.000	0.000	0.000	476.134	210.582	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:30	479.005	242.502	5.999	0.000	0.000	0.000	479.005	242.502	5.999	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:35	465.176	257.723	50.269	0.000	0.000	0.000	465.176	257.723	50.269	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:40	451.348	272.943	94.539	0.000	0.000	0.000	451.348	272.943	94.539	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:45	437.519	288.164	138.809	0.000	0.000	0.000	437.519	288.164	138.809	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:50	423.690	303.384	183.078	0.000	0.000	0.000	423.690	303.384	183.078	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17:55	409.862	318.605	227.348	0.000	0.000	0.000	409.862	318.605	227.348	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:00	605.384	756.853	665.596	0.000	0.000	0.000	605.384	756.853	665.596	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:05	396.033	1195.101	1103.845	0.000	0.000	0.000	396.033	1195.101	1103.845	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:10	353.529	1633.349	1542.093	0.000	0.000	0.000	353.529	1633.349	1542.093	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:15	311.024	2071.598	1980.341	0.000	0.000	0.000	311.024	2071.598	1980.341	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:20	268.519	2191.241	2191.241	0.000	0.000	0.000	268.519	2191.241	2191.241	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:25	226.015	2191.241	2191.241	0.000	0.000	0.000	226.015	2191.241	2191.241	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:30	183.510	2191.241	2191.241	0.000	0.000	0.000	183.510	2191.241	2191.241	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:35	141.006	2191.241	2191.241	0.000	0.000	0.000	141.006	2191.241	2191.241	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:40	93.991	2186.765	2166.041	0.000	0.000	0.000	93.991	2186.765	2166.041	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Figure A.11. Calculation tables (12:30 to 18:40 - Part 2/3).

	9															
	ES to be recharged by grid			ES Profiles Clip (ES Calc)			ES Capacity Profile			BESS Maximim PRR			After DR Demand (at POC)			Tariff
Time	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com (Var)	5	10	Select 3
12:30	579.589	0.000	0.000	579.589	0.000	0.000	35%	57%	100%	0%			2160.512	1131.479	-477.143	S
12:35	583.308	0.000	0.000	583.308	0.000	0.000	35%	57%	100%	0%			2160.512	1139.873	-464.074	S
12:40	587.028	0.000	0.000	587.028	0.000	0.000	34%	57%	100%	0%			2160.512	1148.267	-451.006	S
12:45	590.748	0.000	0.000	590.748	0.000	0.000	34%	57%	100%	0%			2160.512	1156.662	-437.937	S
12:50	594.467	0.000	0.000	594.467	0.000	0.000	33%	57%	100%	0%			2160.512	1165.056	-424.868	S
12:55	598.187	0.000	0.000	598.187	0.000	0.000	33%	57%	100%	0%			2160.512	1173.450	-411.799	S
13:00	601.907	0.000	0.000	601.907	0.000	0.000	32%	57%	100%	0%			2160.512	1181.844	-398.730	S
13:05	600.438	0.000	0.000	600.438	0.000	0.000	31%	57%	100%	0%			2160.512	1191.237	-378.476	S
13:10	598.969	0.000	0.000	598.969	0.000	0.000	31%	57%	100%	0%			2160.512	1200.630	-358.221	S
13:15	597.500	0.000	0.000	597.500	0.000	0.000	30%	57%	100%	0%			2160.512	1210.023	-337.966	S
13:20	596.031	0.000	0.000	596.031	0.000	0.000	30%	57%	100%	0%			2160.512	1219.416	-317.711	S
13:25	594.561	0.000	0.000	594.561	0.000	0.000	29%	57%	100%	0%			2160.512	1228.809	-297.456	S
13:30	593.092	0.000	0.000	593.092	0.000	0.000	29%	57%	100%	0%			2160.512	1238.202	-277.201	S
13:35	591.563	0.000	0.000	591.563	0.000	0.000	28%	57%	100%	0%			2160.512	1247.535	-257.006	S
13:40	590.034	0.000	0.000	590.034	0.000	0.000	27%	57%	100%	0%			2160.512	1256.867	-236.812	S
13:45	588.505	0.000	0.000	588.505	0.000	0.000	27%	57%	100%	0%			2160.512	1266.200	-216.617	S
13:50	586.976	0.000	0.000	586.976	0.000	0.000	26%	57%	100%	0%			2160.512	1275.533	-196.422	S
13:55	585.446	0.000	0.000	585.446	0.000	0.000	26%	57%	100%	0%			2160.512	1284.866	-176.227	S
14:00	583.917	0.000	0.000	583.917	0.000	0.000	25%	57%	100%	0%			2160.512	1294.198	-156.033	S
14:05	584.553	0.000	0.000	584.553	0.000	0.000	25%	57%	100%	0%			2160.512	1315.783	-113.500	S
14:10	585.188	0.000	0.000	585.188	0.000	0.000	24%	57%	100%	0%			2160.512	1337.367	-70.966	S
14:15	585.824	0.000	0.000	585.824	0.000	0.000	24%	57%	100%	0%			2160.512	1358.952	-28.433	S
14:20	586.460	0.000	0.000	586.460	0.000	0.000	23%	57%	100%	0%			2160.512	1380.536	14.100	S
14:25	587.095	0.000	0.000	587.095	0.000	0.000	22%	57%	100%	0%			2160.512	1402.120	56.633	S
14:30	587.731	0.000	0.000	587.731	0.000	0.000	22%	57%	100%	0%			2160.512	1423.705	99.166	S
14:35	578.273	0.000	0.000	578.273	0.000	0.000	21%	57%	100%	0%			2160.512	1435.196	131.607	S
14:40	568.816	0.000	0.000	568.816	0.000	0.000	21%	57%	100%	0%			2160.512	1446.687	164.047	S
14:45	559.358	0.000	0.000	559.358	0.000	0.000	20%	57%	100%	0%			2160.512	1458.179	196.487	S
14:50	549.901	0.000	0.000	549.901	0.000	0.000	20%	57%	100%	0%			2160.512	1469.670	228.927	S
14:55	540.444	0.000	0.000	540.444	0.000	0.000	19%	57%	100%	0%			2160.512	1481.162	261.368	S
15:00	530.986	0.000	0.000	530.986	0.000	0.000	19%	57%	100%	0%			2160.512	1492.653	293.808	S
15:05	530.468	0.000	0.000	530.468	0.000	0.000	18%	57%	100%	0%			2160.512	1521.437	351.893	S
15:10	529.950	0.000	0.000	529.950	0.000	0.000	18%	57%	100%	0%			2160.512	1550.221	409.979	S
15:15	529.432	0.000	0.000	529.432	0.000	0.000	17%	57%	100%	0%			2160.512	1579.004	468.064	S
15:20	528.914	0.000	0.000	528.914	0.000	0.000	17%	57%	100%	0%			2160.512	1607.788	526.150	S
15:25	528.396	0.000	0.000	528.396	0.000	0.000	16%	57%	100%	0%			2160.512	1636.572	584.235	S
15:30	527.878	0.000	0.000	527.878	0.000	0.000	16%	57%	100%	0%			2160.512	1665.355	642.321	S
15:35	524.597	0.000	0.000	524.597	0.000	0.000	15%	57%	100%	0%			2160.512	1691.376	697.643	S
15:40	521.315	0.000	0.000	521.315	0.000	0.000	15%	57%	100%	0%			2160.512	1717.396	752.965	S
15:45	518.034	0.000	0.000	518.034	0.000	0.000	14%	57%	100%	0%			2160.512	1743.417	808.287	S
15:50	514.753	0.000	0.000	514.753	0.000	0.000	14%	57%	100%	0%			2160.512	1769.437	863.610	S
15:55	511.471	0.000	0.000	511.471	0.000	0.000	13%	57%	100%	0%			2160.512	1795.458	918.932	S
16:00	508.190	0.000	0.000	508.190	0.000	0.000	13%	57%	100%	0%			2160.512	1821.478	974.254	S
16:05	502.563	0.000	0.000	502.563	0.000	0.000	12%	57%	100%	0%			2160.512	1852.220	1041.365	S
16:10	496.937	0.000	0.000	496.937	0.000	0.000	12%	57%	100%	0%			2160.512	1882.962	1108.476	S
16:15	491.310	0.000	0.000	491.310	0.000	0.000	11%	57%	100%	0%			2160.512	1913.704	1175.587	S
16:20	485.683	0.000	0.000	485.683	0.000	0.000	11%	57%	100%	0%			2160.512	1944.447	1242.698	S
16:25	480.056	0.000	0.000	480.056	0.000	0.000	10%	57%	100%	0%			2160.512	1975.189	1309.809	S
16:30	474.430	0.000	0.000	474.430	0.000	0.000	10%	57%	100%	0%			2160.512	2005.931	1376.920	S
16:35	472.322	0.000	0.000	472.322	0.000	0.000	9%	57%	100%	0%			2160.512	2040.192	1447.549	S
16:40	470.214	0.000	0.000	470.214	0.000	0.000	9%	57%	100%	0%			2160.512	2074.452	1518.179	S
16:45	468.105	0.000	0.000	468.105	0.000	0.000	9%	57%	100%	0%			2160.512	2108.713	1588.808	S
16:50	465.997	0.000	0.000	465.997	0.000	0.000	8%	57%	100%	0%			2160.512	2142.974	1659.438	S
16:55	463.889	16.722	0.000	463.889	16.722	0.000	8%	57%	100%	0%	1%		2160.512	2160.512	1730.068	S
17:00	461.781	50.983	0.000	461.781	50.983	0.000	7%	57%	100%	0%	2%		2160.512	2160.512	1800.697	S
17:05	464.652	82.903	0.000	464.652	82.903	0.000	7%	57%	100%	0%	1%		2160.512	2160.512	1861.666	S
17:10	467.523	114.823	0.000	467.523	114.823	0.000	6%	57%	100%	0%	1%		2160.512	2160.512	1922.635	S
17:15	470.393	146.743	0.000	470.393	146.743	0.000	6%	57%	100%	0%	1%		2160.512	2160.512	1983.604	S
17:20	473.264	178.662	0.000	473.264	178.662	0.000	5%	56%	100%	0%	1%		2160.512	2160.512	2044.573	S
17:25	476.134	210.582	0.000	476.134	210.582	0.000	5%	56%	100%	0%	1%		2160.512	2160.512	2105.543	S
17:30	479.005	242.502	5.999	479.005	242.502	5.999	5%	56%	100%	0%	1%	0%	2160.512	2160.512	2160.512	S
17:35	465.176	257.723	50.269	465.176	257.723	50.269	4%	56%	100%	1%	1%	2%	2160.512	2160.512	2160.512	S
17:40	451.348	272.943	94.539	451.348	272.943	94.539	4%	55%	100%	1%	1%	2%	2160.512	2160.512	2160.512	S
17:45	437.519	288.164	138.809	437.519	288.164	138.809	3%	55%	100%	1%	1%	2%	2160.512	2160.512	2160.512	S
17:50	423.690	303.384	183.078	423.690	303.384	183.078	3%	55%	100%	1%	1%	2%	2160.512	2160.512	2160.512	S
17:55	409.862	318.605	227.348	409.862	318.605	227.348	2%	55%	99%	1%	1%	2%	2160.512	2160.512	2160.512	S
18:00	605.384	756.853	665.596	605.384	756.853	665.596	2%	54%	99%	9%	20%	20%	1951.161	1737.485	1766.534	P
18:05	396.033	1195.101	1103.845	396.033	1195.101	1103.845	2%	53%	98%	10%	20%	20%	2118.008	1261.919	1296.155	P
18:10	353.529	1633.349	1542.093	353.529	1633.349	1542.093	1%	51%	96%	2%	20%	20%	2118.008	786.353	825.776	P
18:15	311.024	2071.598	1980.341	311.024	2071.598	1980.341	1%	49%	94%	2%	20%	20%	2118.008	310.787	355.397	P
18:20	268.519	2191.241	2191.241	268.519	2191.241	2191.241	1%	47%	92%	2%	5%	10%	2118.008	153.827	112.367	P
18:25	226.015	2191.241	2191.241	226.015	2191.241	2191.241	0%	45%	90%	2%			2118.008	116.509	80.236	P
18:30	183.510	2191.241	2191.241	183.510	2191.241	2191.241	0%	43%	88%	2%			2118.008	79.191	48.105	P
18:35	141.006	2191.241	2191.241	141.006	2191.241	2191.241	0%	41%	86%	2%			2113.498	37.358	11.453	P
18:40	93.991	2186.765	2166.041	93.991	2186.765	2166.041	0%	39%	84%	2%	0%	1%	2113.498	0.000	0.000	P

Figure A.12. Calculation tables (12:30 to 18:40 - Part 3/3).

										0			1			2		
	Low	Weekday	Load Demand		Calculated PV Profiles			ES State	ES State	ES System Ratings (No PV)			ES System Reserve (No PV)			ES & PV Ops (No Surplus Used)		
Time	Norm. data (pu)		Real, incl. MSS		Com	5	10	Rating	Ops.	Com	5	10	Com	5	10	Com	5	10
	Ops:	ES Rating:	Ops:	ES Rating:						68%	68%	68%						
18:45	0.679	0.579	2160.474	1844.440	0.000	15.543	31.086	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:50	0.664	0.554	2113.459	1764.258	0.000	10.362	20.724	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:55	0.649	0.529	2066.444	1684.075	0.000	5.181	10.362	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:00	0.634	0.503	2019.430	1603.893	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:05	0.613	0.484	1951.161	1541.834	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:10	0.591	0.464	1882.892	1479.775	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:15	0.570	0.444	1814.623	1417.716	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:20	0.548	0.425	1746.354	1355.657	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:25	0.527	0.405	1678.085	1293.598	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:30	0.505	0.386	1609.816	1231.539	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:35	0.488	0.377	1556.261	1202.957	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:40	0.471	0.368	1502.706	1174.375	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:45	0.454	0.359	1449.152	1145.794	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:50	0.437	0.350	1395.597	1117.212	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:55	0.421	0.341	1342.042	1088.630	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:00	0.404	0.332	1288.487	1060.048	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:05	0.395	0.327	1260.320	1044.586	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:10	0.386	0.322	1232.153	1029.123	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:15	0.377	0.317	1203.985	1013.661	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:20	0.368	0.312	1175.818	998.199	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:25	0.359	0.307	1147.650	982.736	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:30	0.350	0.302	1119.483	967.274	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:35	0.344	0.298	1098.313	953.205	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:40	0.337	0.293	1077.143	939.136	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:45	0.330	0.289	1055.973	925.068	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:50	0.324	0.284	1034.804	910.999	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:55	0.317	0.280	1013.634	896.930	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:00	0.310	0.276	992.464	882.861	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:05	0.307	0.273	981.073	875.833	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:10	0.303	0.271	969.681	868.804	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:15	0.299	0.269	958.290	861.776	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:20	0.296	0.267	946.898	854.747	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:25	0.292	0.265	935.507	847.719	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:30	0.289	0.262	924.115	840.691	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:35	0.284	0.261	908.400	835.995	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:40	0.279	0.259	892.685	831.299	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:45	0.274	0.258	876.970	826.603	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:50	0.269	0.256	861.254	821.907	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:55	0.264	0.255	845.539	817.211	0.000	0.000	0.000	Disch1	Disch1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:00	0.259	0.253	829.824	812.516	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:05	0.256	0.252	819.935	807.133	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:10	0.253	0.250	810.046	801.751	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:15	0.249	0.248	800.158	796.369	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:20	0.246	0.247	790.269	790.987	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:25	0.243	0.245	780.380	785.604	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:30	0.240	0.243	770.492	780.222	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:35	0.237	0.240	760.332	769.129	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:40	0.234	0.236	750.173	758.035	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:45	0.231	0.233	740.013	746.941	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:50	0.227	0.229	729.854	735.848	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:55	0.224	0.226	719.695	724.754	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:00	0.221	0.222	709.535	713.661	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:05	0.217	0.218	698.603	701.037	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:10	0.214	0.214	687.671	688.413	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:15	0.211	0.210	676.739	675.789	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:20	0.207	0.206	665.808	663.166	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:25	0.204	0.202	654.876	650.542	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:30	0.200	0.198	643.944	637.918	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:35	0.199	0.194	640.595	625.832	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:40	0.198	0.191	637.246	613.746	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:45	0.197	0.187	633.897	601.660	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:50	0.196	0.183	630.548	589.574	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:55	0.195	0.179	627.199	577.488	0.000	0.000	0.000	Charg1	Charg1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

a -->	0.000	-39.90	-79.79
b -->	0.000	919.60	1839.19
c -->	0.000	-3652.27	-7304.55

$f(x) = ax^2 + bx + c$ for PV profiles if fn selected

PCS Rating (No PV, kW):	2191	2191	2191	6026.869	344.349	164.528
ES Rating (No PV, kWh):	8765	8765	8765	└ ES Utilised (With PV, kWh)		
Max C-Rate (Incl. DoD):	0.20	0.20	0.20			
Max discharge from no PV:	1017	1017	1017			
Max recharge from no PV:	1345	1345	1345			
Max req. from min C-rate:	2191	2191	2191			
ΣAmount recharged in Charg1:	-105180	-105180	-105180			
Charg1 recharge per slot:	1345	1345	1345			
ES Reserve (No PV, kWh):	6027	6027	6027			
Spare = Rating - Reserve (No PV, kWh):	2738	2738	2738			
Additional capacity for PV surplus capture (kWh):	0	0	0			

Figure A.13. Calculation tables (18:45 to 23:55 - Part 1/3).

	3			4			5			6			7			8		
	ES & PV (ES Arbitrage Used)			PV Surplus (Avail. for ES use)			ES profile including PV recharg			PV Surplus (For Rem. use)			ES Spare profile			PV Surplus (All ES Charged)		
Time	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com	5	10
18:45	46.976	2144.931	2129.388	0.000	0.000	0.000	46.976	2144.931	2129.388	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:50	0.000	2103.097	2092.735	0.000	0.000	0.000	0.000	2103.097	2092.735	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18:55	0.000	2061.263	2056.082	0.000	0.000	0.000	0.000	2061.263	2056.082	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:00	0.000	2019.430	2019.430	0.000	0.000	0.000	0.000	2019.430	2019.430	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:05	0.000	1951.161	1951.161	0.000	0.000	0.000	0.000	1951.161	1951.161	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:10	0.000	1882.892	1882.892	0.000	0.000	0.000	0.000	1882.892	1882.892	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:15	0.000	1814.623	1814.623	0.000	0.000	0.000	0.000	1814.623	1814.623	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:20	0.000	1746.354	1746.354	0.000	0.000	0.000	0.000	1746.354	1746.354	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:25	0.000	1678.085	1678.085	0.000	0.000	0.000	0.000	1678.085	1678.085	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:30	0.000	1609.816	1609.816	0.000	0.000	0.000	0.000	1609.816	1609.816	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:35	0.000	1556.261	1556.261	0.000	0.000	0.000	0.000	1556.261	1556.261	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:40	0.000	1118.013	1118.013	0.000	0.000	0.000	0.000	1118.013	1118.013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:45	0.000	679.765	679.765	0.000	0.000	0.000	0.000	679.765	679.765	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:50	0.000	241.517	241.517	0.000	0.000	0.000	0.000	241.517	241.517	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:05	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:10	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:15	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:25	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:30	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:05	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:10	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:15	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:25	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:30	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:05	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:10	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:15	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:25	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:30	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:05	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:10	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:15	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:25	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:30	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:55	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

ES balance > 0:	0	18169	65681
Net ES Utilised (kWh):	8765	7251	3292

PV demand available (kW):	0	0	12930
Energy balance (kW):	0	0	0
Uncharged Additional (kW):	0	0	0
Discharged Spare (PV Charged, kWh):	0	0	0
Unused Spare (Surplus PV Charged, kWh):	0	0	0
Uncharged (PV) Spare (kWh):	2738	2738	2738

Figure A.14. Calculation tables (18:45 to 23:55 - Part 2/3).

	9															
	ES to be recharged by grid			ES Profiles Clip (ES Calc)			ES Capacity Profile			BESS Maximim PRR			After DR Demand (at POC)			Tariff
Time	Com	5	10	Com	5	10	Com	5	10	Com	5	10	Com (Var)	5	10	Select 3
18:45	46.976	2144.931	2129.388	46.976	2144.931	2129.388	0%	37%	82%	2%	2%	2%	2113.498	0.000	0.000	P
18:50	0.000	2103.097	2092.735	0.000	2103.097	2092.735	0%	35%	80%	2%	2%	2%	2113.459	0.000	0.000	P
18:55	0.000	2061.263	2056.082	0.000	2061.263	2056.082	0%	33%	78%		2%	2%	2066.444	0.000	0.000	P
19:00	0.000	2019.430	2019.430	0.000	2019.430	2019.430	0%	31%	76%		2%	2%	2019.430	0.000	0.000	P
19:05	0.000	1951.161	1951.161	0.000	1951.161	1951.161	0%	29%	74%		3%	3%	1951.161	0.000	0.000	P
19:10	0.000	1882.892	1882.892	0.000	1882.892	1882.892	0%	27%	72%		3%	3%	1882.892	0.000	0.000	P
19:15	0.000	1814.623	1814.623	0.000	1814.623	1814.623	0%	25%	71%		3%	3%	1814.623	0.000	0.000	P
19:20	0.000	1746.354	1746.354	0.000	1746.354	1746.354	0%	24%	69%		3%	3%	1746.354	0.000	0.000	P
19:25	0.000	1678.085	1678.085	0.000	1678.085	1678.085	0%	22%	67%		3%	3%	1678.085	0.000	0.000	P
19:30	0.000	1609.816	1609.816	0.000	1609.816	1609.816	0%	21%	66%		3%	3%	1609.816	0.000	0.000	P
19:35	0.000	1556.261	1556.261	0.000	1556.261	1556.261	0%	19%	64%		2%	2%	1556.261	0.000	0.000	P
19:40	0.000	1118.013	1118.013	0.000	1118.013	1118.013	0%	18%	63%		20%	20%	1502.706	384.693	384.693	P
19:45	0.000	679.765	679.765	0.000	679.765	679.765	0%	18%	63%		20%	20%	1449.152	769.387	769.387	P
19:50	0.000	241.517	241.517	0.000	241.517	241.517	0%	17%	62%		20%	20%	1395.597	1154.080	1154.080	P
19:55	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%		11%	11%	1342.042	1342.042	1342.042	P
20:00	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1288.487	1288.487	1288.487	P
20:05	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1260.320	1260.320	1260.320	P
20:10	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1232.153	1232.153	1232.153	P
20:15	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1203.985	1203.985	1203.985	P
20:20	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1175.818	1175.818	1175.818	P
20:25	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1147.650	1147.650	1147.650	P
20:30	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1119.483	1119.483	1119.483	P
20:35	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1098.313	1098.313	1098.313	P
20:40	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1077.143	1077.143	1077.143	P
20:45	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1055.973	1055.973	1055.973	P
20:50	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1034.804	1034.804	1034.804	P
20:55	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				1013.634	1013.634	1013.634	P
21:00	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				992.464	992.464	992.464	S
21:05	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				981.073	981.073	981.073	S
21:10	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				969.681	969.681	969.681	S
21:15	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				958.290	958.290	958.290	S
21:20	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				946.898	946.898	946.898	S
21:25	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				935.507	935.507	935.507	S
21:30	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				924.115	924.115	924.115	S
21:35	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				908.400	908.400	908.400	S
21:40	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				892.685	892.685	892.685	S
21:45	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				876.970	876.970	876.970	S
21:50	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				861.254	861.254	861.254	S
21:55	0.000	0.000	0.000	0.000	0.000	0.000	0%	17%	62%				845.539	845.539	845.539	S
22:00	0.000	0.000	0.000	-269.001	-222.534	-101.021				12%	10%	5%	1098.825	1052.357	930.844	S
22:05	0.000	0.000	0.000	-538.003	-445.067	-202.041				12%	10%	5%	1357.938	1265.002	1021.976	S
22:10	0.000	0.000	0.000	-807.004	-667.601	-303.062				12%	10%	5%	1617.051	1477.647	1113.108	S
22:15	0.000	0.000	0.000	-1076.006	-890.135	-404.082				12%	10%	5%	1876.163	1690.293	1204.240	S
22:20	0.000	0.000	0.000	-1345.007	-1112.669	-505.103				12%	10%	5%	2135.276	1902.938	1295.372	S
22:25	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2125.387	1893.049	1285.483	S
22:30	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2115.499	1883.160	1275.595	O
22:35	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2105.339	1873.001	1265.435	O
22:40	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2095.180	1862.841	1255.276	O
22:45	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2085.021	1852.682	1245.116	O
22:50	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2074.861	1842.523	1234.957	O
22:55	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2064.702	1832.363	1224.797	O
23:00	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2054.542	1822.204	1214.638	O
23:05	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2043.610	1811.272	1203.706	O
23:10	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2032.678	1800.340	1192.774	O
23:15	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2021.747	1789.408	1181.842	O
23:20	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							2010.815	1778.476	1170.910	O
23:25	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1999.883	1767.544	1159.979	O
23:30	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1988.951	1756.613	1149.047	O
23:35	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1985.602	1753.264	1145.698	O
23:40	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1982.253	1749.915	1142.349	O
23:45	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1978.904	1746.566	1139.000	O
23:50	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1975.555	1743.217	1135.651	O
23:55	0.000	0.000	0.000	-1345.007	-1112.669	-505.103							1972.206	1739.868	1132.302	O

Com	5	10	
8765	7251	3292	: Discharged ES (kWh)
-2738	-1224	2735	: Reserve Status (kWh)
-105180	-87011	-39499	: ΣRecharged in Charg1 (<= 0, kW)
1345	1113	505	: Charg1 recharge per slot (>0, kW)

	Com	5	10
Max ES Cap:	100%	100%	100%
Lowest ES Cap:	0%	17%	62%
Max ES Cap utilised:	100%	83%	38%
Unused ES Cap (kWh):	0	1514	5473

	Com	5	10
Max PRR:	41.60%	20.00%	20.00%
Max Check:	1	0	0

	Com	5	10
Off-Peak (kWh):	13885	12013	7390
Std (kWh):	19524	13684	5760
Peak (kWh):	9349	2685	1821
Feed-In (kWh):	0	0	-1268
MD (kW):	2161	2161	2161
MD (Time):	0	1	1

Figure A.15. Calculation tables (18:45 to 23:55 - Part 3/3).

A.1.5 Demand checks

Figure A.16 to Figure A.20 illustrates the various subcomponents of the DR profile in reference to Section 3.6.1 and Figure 3.16 to Figure 3.20. $ES_{n,Cap}$ is an additional check confirming the status (overcharge and DoD limitations) of available ES capacity.

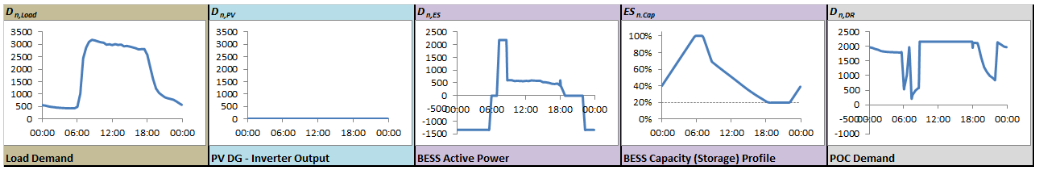

Figure A.16. DR profile subcomponent breakdown (PV_{Pen} = 0%).

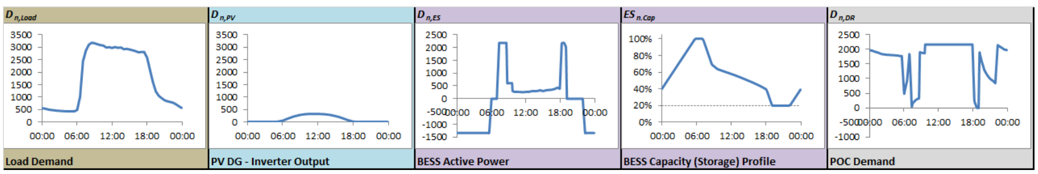

Figure A.17. DR profile subcomponent breakdown (Clear sky PV_{Pen} = 10%).

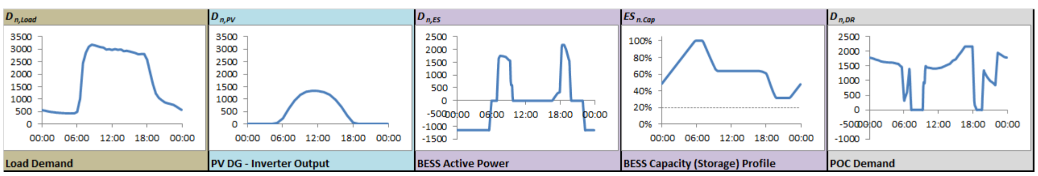

Figure A.18. DR profile subcomponent breakdown (Clear sky PV_{Pen} = 42%).

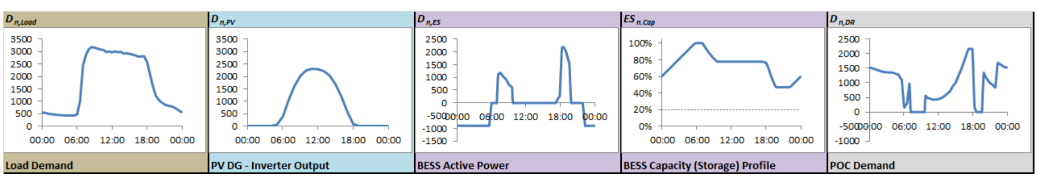

Figure A.19. DR profile subcomponent breakdown (Clear sky PV_{Pen} = 73%).

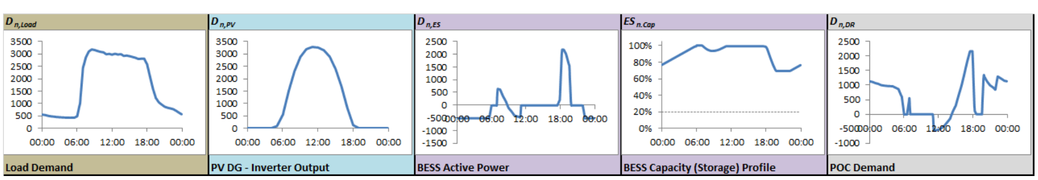

Figure A.20. DR profile subcomponent breakdown (Clear sky PV_{Pen} = 104%).