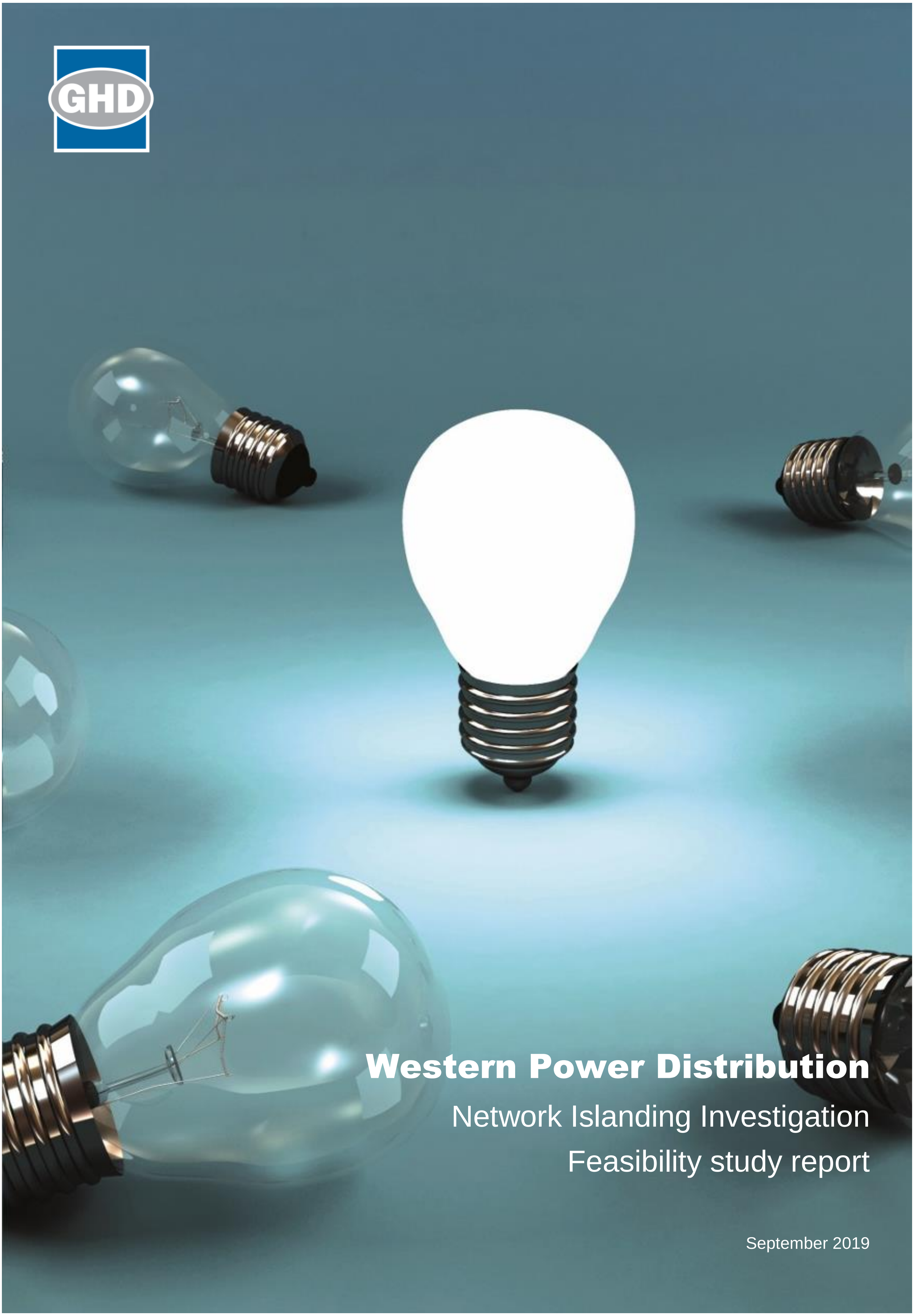

# Western Power Distribution

## Network Islanding Investigation

## Feasibility study report

September 2019

WATER | ENERGY & RESOURCES | ENVIRONMENT | PROPERTY & BUILDINGS | TRANSPORTATION

# Glossary

| Acronym | Definition |
|---|---|
| ADMD | After Diversity Maximum Demand |
| BSP | Bulk Supply Point |
| CBA | Cost Benefits Analysis |
| CCGT | Combined Cycle Gas Turbine |
| CHP | Combined Heat and Power |
| DER | Distributed Energy Resources |
| DG | Distributed Generation |
| DNO | Distribution Network Operator |
| DSO | Distribution System Operator |
| DUOS | Distribution Use of System |
| EfW | Energy from Waste |
| EHV | Extra High Voltage |
| EMID | (Western Power Distribution) East Midlands |
| ESCo | Energy Service Company |
| ESO | Electricity System Operator |
| GSP | Grid Supply Point |
| LDC | Load Duration Curve |
| LTDS | Long Term Development Statement |
| MD | Maximum Demand |
| MPAN | Meter Point Administration Number |
| MW | Mega Watt |
| NIC | Network Innovation Competition |
| NMS | Network Management System |
| NPV | Net Present Value |
| NTBM | Non-traditional Business Model |
| OCGT | Open Cycle Gas Turbine |
| O&M | Operation and Maintenance |
| PCC | Point Common Coupling |
| PMR | Pole Mounted Recloser |
| S STN | Substation |
| STOR | Short Term Operating Reserve |
| TDCV | Typical Domestic Consumption Value |
| TUOS | Transmission Use of System |
| UOS | Use of Systen |
| WPD | Western Power Distribution |

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# 1. Introduction

## 1.1 Context of project

Around the world, low carbon technologies have led to a trend of generating power locally to customers from Distributed Generation (DG) connected to the distribution system, including renewable energy resources. Due to rapid demand growth, the system requires an increasing amount of generation. Enhanced use of renewable generators within distribution networks calls for a growing level of network flexibility, whilst maintaining the existing standard for safety. It is expected that the utilisation of Distributed Energy Resources (DER) will support the transition to generate low carbon power with much lesser environmental impact and lower costs for customers.

Islanding of DG under current practice should be avoided. Typical safety schemes for DG include under/over voltage and under/over frequency protection, which prevent continued supply to customers in an islanded section of the network. In addition, Loss of Grid protection ensures that disconnected circuits remain de-energised and thus enabling a safe and secure network.

The Network Islanding Investigation project aims to understand whether intentional islanding of certain sections of network would allow them to be operated in a safe and secure manner, and whether this represents a new tool for Distribution Network Operators (DNOs) to increase network flexibility. The theory is that network islanding could provide significant benefits for customers and support DNOs with the transition to Distribution System Operator (DSO).

## 1.2 The aim of this report

The aim of this report is to investigate the feasibility of network islanding by implementing a Cost Benefit Analysis (CBA) of the approach when applied to selected trial networks. The report describes the methodology that has been employed; the technical criteria and assumptions that have been used; and the subsequent results of the CBA along with associated commentary. More specifically, the report aims to formally document:

- The methodology for identification of possible trial networks for the study;
- The identification of technical criteria to allow the selection of the trial networks for the study;
- The assumptions used to underpin the technical requirements for the formation of the islands and implementation of the financial analysis;
- The methodology used to implement the CBA; and
- Discussion of the results of the analysis including:
  - Commentary on the optimum scale of network islands to maximise customer benefit;
  - Review of the legal, regulatory and commercial arrangements related to network islanding; and
  - Review of the requirements for stakeholder engagement.

## 1.3 Scope of the study

The financial analysis will be applied to two types of network island:

1. Islands formed from existing distribution network (**existing islands**). These are sections of existing network that have controllable DG that can be isolated from the main interconnected system for customer benefit; and
2. Islands formed from new developments connecting to the distribution network (**new development islands**). These are new residential, commercial and/or industrial developments that could be operated isolated from the main interconnected system for customer benefit.

## 1.4 Tasks and deliverables

Table 1-1 highlights task 4 of the Network Islanding Investigation project, which is the subject of this report.

**Table 1-1 Network Islanding Investigation tasks**

| |
|---|
| **Task 1:** Data Gathering |
| **Task 2:** High-Level Review |
| **Task 3:** High-Level Research and Analysis |
| **Task 4:** Feasibility Study |
| **Task 5:** Further Investigation |
| **Task 6:** Network Modelling |
| **Final project deliverable:** Network Islanding Investigation Findings Report |

# 2. Identification of trial areas

The following sub-sections describe the methodology adopted and results of the assessment to identify potential trial areas for implementation of network islanding.

The methodology for the identification of potential trial areas looks to achieve a broad range of candidates with different characteristics, to provide an opportunity to investigate the extent of the feasibility of islanding. The potential areas identified in this section were carried forward to provide a realistic basis for the subsequent assessments, as follows:

- Plan to implement network islanding, presented in section 3.2;
- Preliminary quantification of financial costs and benefits, presented in section 3.2 and 3.3; and
- Investigation of the optimum scale of network islands, presented in section 3.4.

## 2.1 Methodology to identify trial areas

The following methodology was developed for the identification of suitable network islanding trial areas:

1. A set of criteria was developed that allowed the identification of a shortlist of networks suitable for the implementation of islanding. These are as follows:
   a) Existing network islands: areas were sought from information available from the Long Term Development Statement (LTDS) and the WPD DG register:
      i. With capability to be isolated from the main interconnected system safely and without disruption to customers; and
      ii. With installed capacity of controllable generation[1] greater than 150% of the peak demand.
   b) New development islands: areas were sought from public information produced by private developers and local authorities:
      i. For planned developments of more than 3,000 dwellings, i.e. those that were deemed to have sufficiently high demand for electricity and high likelihood of development of generation capacity.
2. A data request was issued to WPD for EMU/PowerOn diagrams of the shortlisted areas and MW half-hourly data for the generation export and loads contained within them;
3. The shortlisted trial networks were then investigated in greater detail. This was carried out to understand whether the sites had the required technical characteristics to be considered for the study:
   a) For existing network islands: the EMU/PowerOn diagrams received from WPD were reviewed to confirm the switching arrangements required to form the island and whether this could be implemented safely and practically on the system. In addition, the completeness of the half-hourly data supplied by WPD was reviewed to understand whether it would be possible to implement the CBA. In cases where

[1] At this stage potential islands considered have exclusively comprised generation whose output can be controlled by changing the input of the fuel source, for example CHP, energy from waste, landfill gas.

insufficient data was available and it was deemed that realistic assumptions could not be made, candidate islands were not taken forward for site selection.

b) For new development islands: a further review of the publically available documentation was undertaken to understand the exact number of dwellings and type of installations (i.e. commercial, industrial) contained within each of the shortlisted candidate sites. The sites used for the feasibility study were those that had detailed information on the aforementioned so that the feasibility study could be performed.

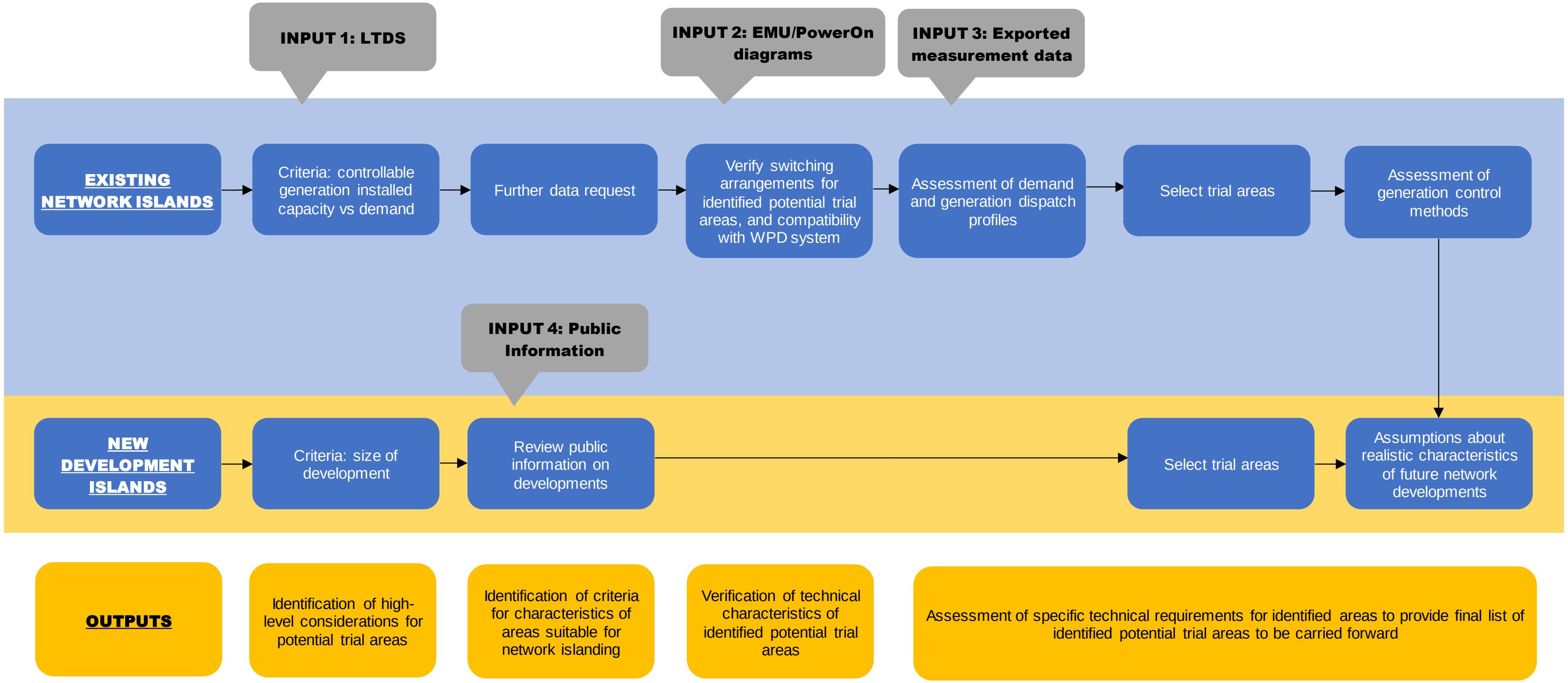


**Figure 2-1: Illustration of methodology adopted to identify potential trial areas**

## 2.2 High level considerations

Building on earlier work, and as agreed during the project meeting on 30/04/2019, the following high level considerations will be addressed in this Feasibility Study relating to implementation of network islanding:

- Applied to both **existing network** and **new developments**;
- At the behest of WPD, to provide **financial benefits to WPD's customers**; and
- In the context of existing legal, regulatory and commercial arrangements, with required changes identified.

## 2.3 Technical criteria for network islands

This study has focussed on the identification of network islands on WPD's 33kV distribution network. The motivation for this was twofold:

- The majority of controllable DG is connected at this voltage level. Therefore, this voltage level was chosen to ensure there was a large selection of networks for inclusion in the feasibility study; and
- To understand the benefits of islanding in the most likely real-world trial scenario. Islanding is most likely to be trialled on the 33kV network because the trial areas are more manageable in size (compared with 11kV networks) and the impact on customers is much lower (compared with the 132kV and 66kV networks).
- Application of network islands on the 11kV network was investigated at the early stages of the feasibility study, however, it was found that the data required for CBA analysis was either not available or not sufficiently accurate/complete. It was, therefore, decided that 11kV network islands would not be investigated further in the feasibility study.

A set of high level criteria has been proposed in this study to define the technical characteristics of potential trial islands. These criteria are a common set of rules that have allowed the process to select trial islands to be carried out. The criteria are as follows:

- The trial network islands must have at least one controllable DG;
- The installed capacity of controllable DG needs to be greater than 1.5 times the peak demand for the sum total of the loads within the island; and
- Only new developments with greater than 3,000 homes are considered to have sufficiently high electricity demand to be considered for a new development island.

A combination of the WPD LTDS and detailed DG register was reviewed to generate a shortlist of candidate networks that were recorded and taken forward for more detailed investigation.

## 2.4 Site selection

### 2.4.1 Existing network islands

As previously discussed, the LTDS and detailed DG register was used as an initial step to identify potential islands that could be included in the feasibility study. This analysis generated a number of potential islands on the 33kV network that could be supplied from local controllable DG. A shortlist of suitable islands was created on the basis of this detailed review.

A data request was submitted to WPD for a full year (2018) of half-hourly MW data for the demands and generators contained within the shortlisted islands as well as EMU/PowerOn diagrams for the selected areas. The MW data was required to perform the feasibility study analysis that forms the basis of this report.

The next step was to review the EMU/PowerOn diagrams of the shortlisted networks. This more detailed review enabled verification of whether the islands could be implemented practically by investigating the switching arrangements that would have to be performed to create the islands.

Table 2-1 provides the details of the islands that were selected for analysis in this feasibility assessment. Further details about the characteristics of these islands are provided in Appendix A.

**Table 2-1: Selected network islands**

| Island Code | Licence Area | Area | Generator Name | Generation type | Capacity / scale | Load Supplied (Primary / MW) |
|---|---|---|---|---|---|---|
| EM1 | East Midlands | Wellingborough | Wykes Generation | Biomass CHP | 25.00 MW @ 33 kV | Sharnbrook / 5.6<br>Harrold / 1.5 |
| EM2 | East Midlands | Wellingborough | Wykes Generation | Biomass CHP | 25.00 MW @ 33 kV | Little Irchester / 14.8 |
| EM3 | East Midlands | Nottingham | Redfield Road 1 STOR | Dedicated Biomass | 20.88 MW @ 33 kV | Wollaton Road / 22.5 |
| EM4 | East Midlands | Halfway, Sheffield | Holbrook | Biomass CHP | 5.85 MW @ 33 kV | Halfway TA / 3.3 |

### 2.4.2 New development islands

A list of new developments in WPD's licence areas was produced by researching publically available documentation from the construction and house building industry as well as from local council planning applications. The developments within WPD's licence areas that had sufficient information about the number of dwellings and conformed to the high level criteria were selected for this study. Table 2-2 provides details of the new developments that could form potential new development islands.

**Table 2-2: Selected new development islands**

| Island Code | Location | Generation / development type | Capacity / scale |
|---|---|---|---|
| - | 2022 Commonwealth Games Village, Birmingham | Sport Village | 3,000 homes and sport centre |
| - | Ashton Green next to Leicester | Urban Village | Up to 3,000 homes and commercial sites extended to 130 hectors |
| - | Fairham Pasture, Rushcliffe Borough Council | Homes and workplaces | 3,000 homes, 100,000 sq. meters area |
| - | Great North Zone, Swansea City | Housing development | 4,979 homes |
| ND1 | Representative new development | Housing development plus typical facilities | 3,000 homes |

## 2.5 Assessment of specific technical requirements

### 2.5.1 Assessment of demand and generation dispatch profiles

Analogue measurement data requested for each potential area were assessed to gain an understanding about the historic profiles of demand and generation dispatch in the relevant areas of the network.

In the first instance, where measured data were provided they have been plotted and reviewed for consistency and to identify figures that may correspond unusual system behaviour or data issues. Filtering of data included replacements or correction of unrealistic measurements, according to neighbouring data in previous half-hour. The following figures (Figure 2-2, Figure 2-3, Figure 2-4) show examples of the measured data plotted chronologically, for the whole year, one week and a day, respectively. Load profiles provide an idea of the demand at any instant of time during a year, week or day.

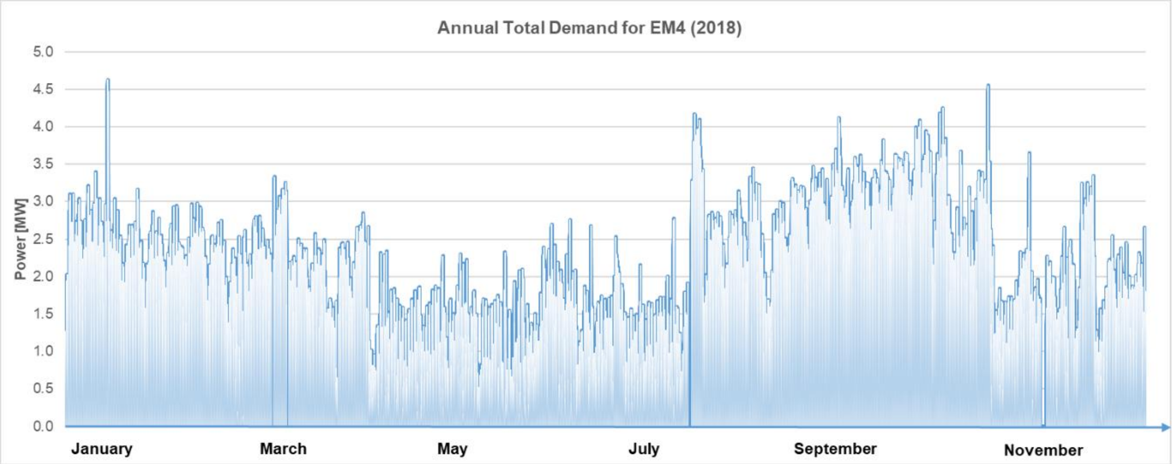


**Figure 2-2: Measured data (full year) for EM4 (Halfway, Sheffield)**

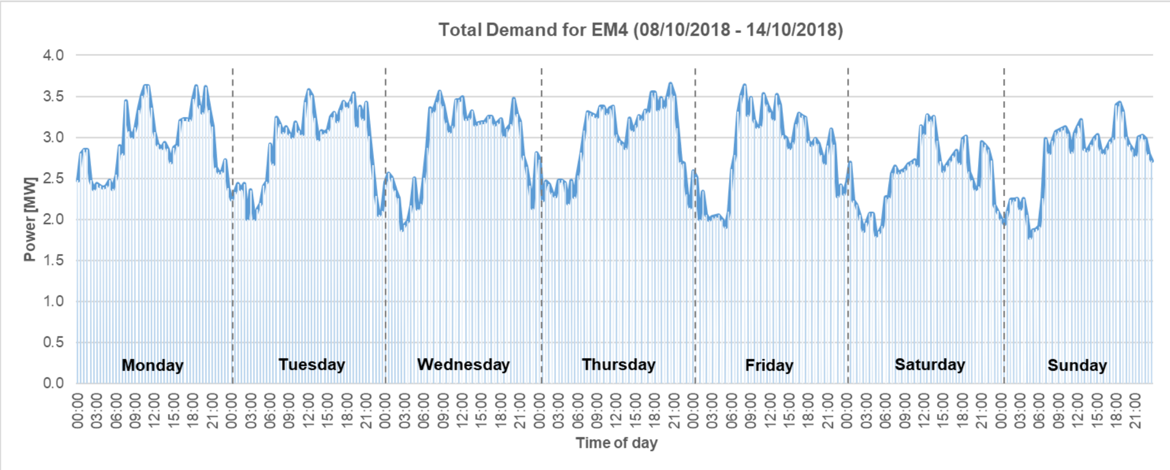


**Figure 2-3: Measured data (week) for EM4 (Halfway, Sheffield)**

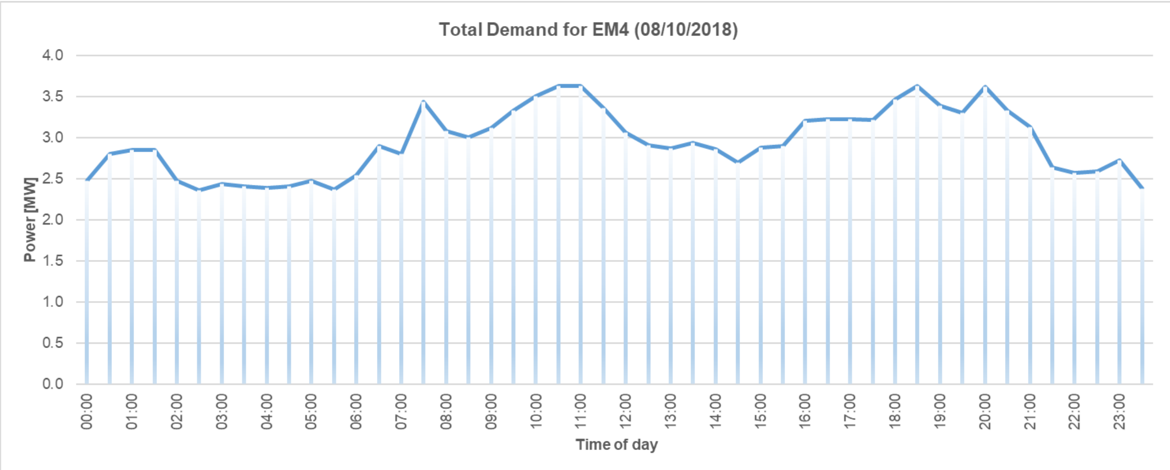


**Figure 2-4: Measured data (day) for EM4 (Halfway, Sheffield)**

After being reviewed to inform the site selection, the measured data were carried forward to be used in the Feasibility Study analysis.

The approach of converting the raw data to load duration curve (LDC) representations was adopted, as described in sub-section 3.3.2. This allows the chronological data to be plotted in a simpler form to more easily compare operating behaviour and evaluate benefits in the CBA. Examples of the simple LDC representation are provided in Figure 3-3 and Figure 3-5.

### 2.5.2 Assessment of generation control methods

The islands were selected on the basis that each one included a single controllable generating source capable of supplying the total peak demand within the island. This approach was adopted to simplify the feasibility study analysis. Renewable generation was excluded from the study as this type of intermittent generation cannot solely be relied upon to supply islanded demand. The ratio of the generator export capacity to the total islanded peak demand has been set to a minimum of 1.5. This factor was chosen to provide a reasonable margin of generator capacity to ensure that the island can be sustained under peak demand conditions and to avoid unnecessarily high loading of the generator.

For the islands identified in Table 2-1, it was assumed that each of the generators is operating with a basic control system that is only suitable for operation in grid connected mode. Therefore, the feasibility study has assumed that a more advanced control system will be need to be retrofitted onto the respective generators to provide the required voltage and frequency control to sustain islanded operation.

A flat Capex cost of £100,000 has been apportioned for this control system for each generator. This covers the supply and installation of new transducers, sensors and actuators along with a new control panel in the generator control building.

### 2.5.3 Assumptions about realistic characteristics of future new developments

A set of assumptions has been identified which enable the implementation of the feasibility analysis on the new development islands selected in Table 2-2. These are as follows:

- The After Diversity Maximum Demand (ADMD) has been assumed to be the standard value of 2.5 kW per customer[2];
- The total calculated maximum demand is taken as the multiplication of the ADMD with the total number of customers in the development;
- The rating of the controllable generator that would have to be installed as part of the new development island is 1.5 times the estimated maximum demand;
- The type of generator selected for the new development islands is assumed to be a gas-fired Combined Cycle Gas Turbine (CCGT) CHP unit. This is a modern highly efficient energy generation technology that would likely be used for supplying electricity and heat demand for a new residential community of the scale identified in this study;
- The electrical infrastructure required to provide the connection for the new development to the main interconnected network is consistent between islanded (counterfactual) and non-islanded (base case) scenarios and is, therefore, not included in the NPV analysis; and

[2] The standard ADMD is based on a typical mix of domestic, commercial and industrial customers. If the island is predominantly made up of domestic customers then the ADMD is expected to reduce to a figure of 2 kW per customer. More detailed assessment of commercial and industrial demand would be based on figures for estimated demand per unit of floor area of the premises.

- The NPV analysis for the counterfactual case includes the capex costs associated with the construction of the CCGT CHP generation to support the new development islands.

# 3. Feasibility Study

## 3.1 Methodology to undertake Feasibility Study

The following section describes the methodology that has been used to implement the feasibility study analysis for network islanding:

1. Plan to implement network islanding, as follows:

    a) A list of required equipment was prepared for each potential trial area identified. This included:

        i. Generator control systems (new control panel, sensors and actuators to enable voltage and frequency control within the islanded network);

        ii. Earthing (to ensure earth fault current has a path to the source within the islanded network);

        iii. Protection relays (capable of adapting to grid-connected and island modes of operation);

        iv. Synchronisation equipment (advanced automatic synchronising panels and associated relays);

        v. Telecommunication systems (to enable the additional signal exchanges between equipment installed as part of the new islands);

    b) Unit costs will be used to assess the capital costs of implementation of network islands in each case.

2. The high level assessment of the financial benefits of network islanding has included the following factors:

    a) Reduced network use of system charges (TUOS and DUOS) for islanded customers;

    b) Capital expenditure for the equipment required to facilitate network islanding; and

    c) Compensation to the existing DG for lost export revenue (generation output reduces to match demand profile).

3. The preliminary Cost Benefit Analysis (CBA) of network islanding, which will comprise:

    a) Development of a spreadsheet to analyse the combined financial costs and benefits for comparison with the relevant counterfactual case;

    b) Use of the spreadsheet to assess sensitivities of the CBA to uncertain external factors; and

    c) Use of the spreadsheet to investigate the optimum scale of network islands through breakeven/tipping-point analysis of capital cost of implementing islanding vs. savings in operating costs.

4. Further high level review, which comprises:

    a) High level review of legal, regulatory and commercial arrangements related to implementation of network islands, and necessary stakeholder engagement; and

    b) High level review of the requirements for stakeholder engagement.

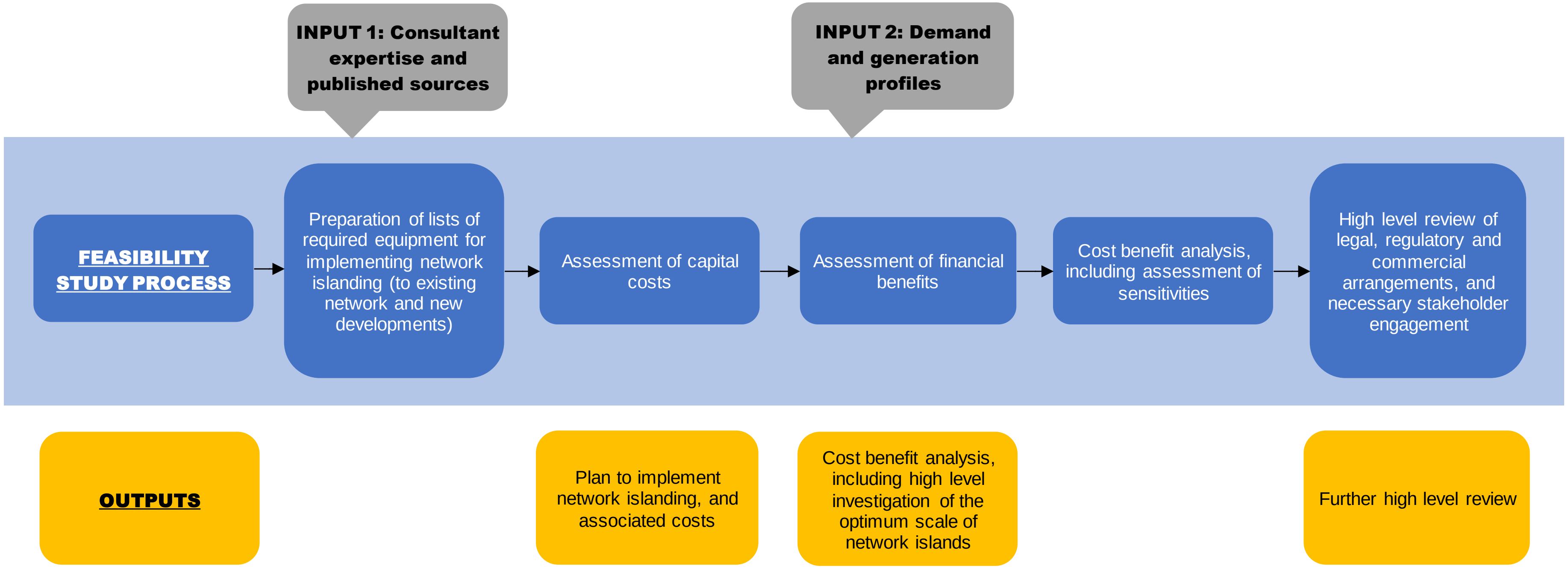


**Figure 3-1: Illustration of methodology adopted for Feasibility Study**

## 3.2 Plan to implement network islanding

### 3.2.1 Technical solutions and lists of required equipment

To accurately consider the feasibility of network islanding it was necessary to identify the technical solutions that would need to be applied to the trial networks to allow them to operate as sustainable network islands. The technical solutions that were identified as follows:

- **Generator control system** – It is anticipated that existing controllable generators would not be configured to control the frequency and voltage for a network island. It has therefore been assumed that a new generator control system would have to be retrofitted onto the generator units to allow suitable control of frequency and voltage in islanded mode.
- **Synchronising panel** – The network island will usually have a single Point of Common Coupling (PCC) to the main interconnected network. A synchronising panel and associated synchronising check relays will need to be installed at the PCC to enable the island control system to safely connect and disconnect the island from the grid.
- **Earthing** – It has been assumed that the trial network islands will require additional earthing to be installed. The earthing is required to provide a path for earth fault current during operation in island mode. The earthing would likely be installed at the PCC, however, the exact location would have to be determined through a detailed study.
- **Protection system updates** – The transition from grid connected to island operational modes will significantly lower fault level as there will no longer be the infeed from the main grid. The protection relays inside the island will therefore require to be modern numerical relays with the group settings capability. A study will be required to identify relays that will need to be replaced and a subsequent relay replacement program will need to be implemented.
- **Power system and protection system studies** – A number of power system studies will have to be performed on the trial networks to understand the behaviour of the system under various switching and fault scenarios. The studies will also have to be performed to calculate the protection settings required for the protection schemes under both grid connected and island operational modes.
- **Telecommunication systems** –The overall control of the island i.e. disconnection/reconnection to the main grid will either be the responsibility of the incumbent DNO or there may be a third party operator such as a DSO. In both instances new telecoms interfaces will be required to the PCC and generator control systems. In the case of the third party operator they will need an additional interface system to the DNO's NMS. Therefore, there is a requirement for new telecommunications systems to cater for this data exchange.

### 3.2.2 Distribution network equipment costs for islanding

To implement the feasibility analysis, cost estimates have been produced for the technical solutions outlined in the section above. These costs have been derived from experience in procuring and installing equipment on the distribution network through working with WPD on multiple innovation projects in the past. They provide a reasonable estimate of the expenditure required to study, design and control a network island. The costs have been split into two categories:

1. Fixed costs – These costs are common to each of the islands selected for this feasibility study have been included in Table 3-1 below.
2. Variable costs – These costs are different for each of the islands and are attributable to the cost of new switchgear and the replacement of protection relays that are not suitable for islanded operation. The costs for the variable elements have been recorded in Table 3-2 for the respective trial island networks.

With regard to the variable costs, the total number of relays to be replaced was calculated by finding the total number of 33kV circuit breakers in each of the trial networks and multiplying this value by the average number of relays per circuit breaker that are anticipated to be replaced. It was assumed that there would be approximately two relay replacements per circuit breaker. The number of circuit breakers was recorded for each of the network islands after reviewing the EMU diagrams in the trial area identification phase of the study.

**Table 3-1: Fixed capex items**

| Fixed Expenditure Items | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Technical solution** | **Sub task** | **Description** | **£/day** | **Man-days** | **Unit cost (£k)** | **Units per Island** | **Subtotal per Island (£k)** |
| Generator Control System | N/A | Supply and install of new control equipment and panel for existing generator | - | - | 100 | 1 | **100** |
| Synchronising Panel | N/A | Supply and install of new synchronising panel | - | - | 50 | 1 | **50** |
| Earthing | N/A | Supply and install of new earthing for the island | - | - | 50 | 1 | **50** |
| Telecommunication Systems | N/A | Supply and install of new telecoms equipment and interfaces | - | - | 100 | 1 | **100** |
| Power System and Protection System Studies | Assessment of existing protection schemes | Study to determine number of relay replacements required | 400 | 15 | - | - | **6** |
| | Studies to determine new protection settings | Studies to determine new protection settings | 400 | 15 | - | - | **6** |
| | | | | | | **Total** | **312** |

**Table 3-2: Variable capex items**

| Variable Expenditure Items | | | | | | |
|---|---|---|---|---|---|---|
| **Island** | **Technical Solution** | **Sub task** | **No. new units** | **Unit Cost (£k)** | **Cost (£k)** | **Subtotal (£k)** |
| EM1 | New 33kV circuit breakers | N/A | 1 | 50 | 50 | - |
| | Protection System Updates | Replacement of relays | 32 | 4 | 128 | **178** |
| EM2 | New 33kV circuit breakers | N/A | 1 | 50 | 50 | - |
| | Protection System Updates | Replacement of relays | 28 | 4 | 112 | **162** |
| EM3 | New 33kV circuit breakers | N/A | 0 | 50 | 0 | - |
| | Protection System Updates | Replacement of relays | 24 | 4 | 96 | **96** |
| EM4 | New 33kV circuit breakers | N/A | 0 | 50 | 0 | - |
| | Protection System Updates | Replacement of relays | 16 | 4 | 64 | **64** |
| | | | | | **Total** | **500** |

### 3.2.3 Operating costs

In addition to the equipment costs for distribution equipment to implement network islands, the operating costs in the base case and islanding counterfactual comprise the:

- Network use of system (UOS) charges - TUOS for the transmission and DUOS for the distribution network; and
- Wholesale generation cost.

*DUOS charges*

The following table presents selected DUOS charges taken from the WPD schedule of DUOS charges for customers in the East Midlands licence area, provided in Appendix B. The selected DUOS charges, used in the model, are those for demand customers (domestic unrestricted); and EHV generator (site-specific for Wykes Generation). It should be noted that normally embedded generation would be expected to have a negative variable DUOS charge (representing its contribution to reducing demand on the system). However, the site-specific charge for Wykes is zero, which indicates that the area has excess generation connected.

**Table 3-3: WPD (EMID) DUOS charges**

| | Assumptions | Unit | Rate |
|---|---|---|---|

| | | | |
|---|---|---|---|
| DUOS - demand customers - unit charges | Domestic unrestricted: Fixed charge | p/MPAN/day | 3.350 |
| | Domestic unrestricted: Unit charge | p/kWh | 2.085 |
| DUOS - site-specific EHV generator - unit charges | EHV generation: Export Super Red unit charge | p/kWh | 0.000 |
| | EHV generation: Export fixed charge | p/day | 0.000 |
| | EHV generation: Export capacity charge | p/kVA/day | 0.000 |
| | EHV generation: Export exceeded capacity charge | p/kVA/day | 0.000 |

The above fixed DUOS charges have been applied to the estimated number of customers (corresponding to the number of Meter Point Administration Numbers, MPANs). The number of customers has been estimated using a high level assumption that all demand customers fall into the domestic unrestricted category, with an annual Typical Domestic Consumption Value (TDCV) of 3,100 kWh, as published by Ofgem[3].

The above variable DUOS charges have been applied to the quantities of energy consumed and generated in the particular island counterfactual cases and corresponding base cases, based on actual measured data provided.

***TUOS charges***

In addition, the Ofgem assessment of the average electricity transmission network charge per domestic customer[4], £35/customer/year, has been adopted for the applicable TUOS charges.

***Wholesale generation costs***

An average GB wholesale electricity price of 6.2p/kWh has been applied to the quantities of energy consumed and generated in the particular island counterfactual cases and corresponding base cases, based on actual measured data provided. The average wholesale price was calculated from figures presented in the Ofgem infographic on energy bills, prices and profits[5]; namely the average annual electricity bill of £577 and the portion of the bill attributed to wholesale energy costs (33.5%), along with the TDCV of 3,100 kWh stated above.

The average whole price is taken to represent the average price paid by supply companies to generators. Precise payments to specific generators will vary by technology, location and agreed contractual terms. However, such details are commercially sensitive and not available for our work.

### 3.2.4 Generator costs in the case of islanding for new developments

In the case of islands for new developments, the capital and operation and maintenance costs of the generator required for the new development has been added to the costs for implementation of the island. This is a conservative approach to allocate all of this cost to the implementation of the island, since there are other benefits and revenue streams. However, the generation capacity is critical to being able to implement an island. Typical generator units capex and opex costs used within the assessments are detailed in Table 3-4.

[3] https://www.ofgem.gov.uk/electricity/retail-market/monitoring-data-and-statistics/typical-domestic-consumption-values
[4] https://www.ofgem.gov.uk/data-portal/estimated-network-costs-domestic-customer-gb-average
[5] https://www.ofgem.gov.uk/publications-and-updates/infographic-bills-prices-and-profits

### Table 3-4: Generator unit costs

| Technical solution | Description | Unit cost |
|---|---|---|
| **Capex (£/kW)** | CCGT CHP | 841 |
| | OCGT | 811 |
| | Recip Diesel | 420 |
| | Recip Gas | 480 |
| | Dedicated Biomass | 3,027 |
| | Biomass CHP | 4,836 |
| | EfW | 8,582 |
| **Fixed O&M (£/MW/year)** | CCGT CHP | 28,200 |
| | OCGT | 9,900 |
| | Recip Diesel | 10,000 |
| | Recip Gas | 10,000 |
| | Dedicated Biomass | 65,500 |
| | Biomass CHP | 223,500 |
| | EfW | 139,500 |
| **Variable O&M (£/MWh)** | CCGT CHP | 5 |
| | OCGT | 4 |
| | Recip Diesel | 2 |
| | Recip Gas | 2 |
| | Dedicated Biomass | 8 |
| | Biomass CHP | 11 |
| | EfW | 25 |
| **Fuel cost (£/MWh)** | CCGT CHP | 54 |
| | OCGT | 52 |
| | Recip Diesel | 119 |
| | Recip Gas | 53 |
| | Dedicated Biomass | 33 |
| | Biomass CHP | 41 |
| | EfW | -110 |

## 3.3 Assessment of financial benefits

### 3.3.1 Nature of benefits

The primary focus of this project is to determine whether network islands can be implemented by WPD to provide financial benefits to customers. As such, the potential financial benefits identified in the High Level Research and Analysis Report have been explored further in this Feasibility Study. The scope of this part of the study is limited to the assessment of financial costs and benefits to customers. Possible additional benefits have not been investigated in this Feasibility Study, but will be considered in the next phase including monetisation of intangible benefits where appropriate.

In developing the Feasibility Study analysis, assumptions have been adopted to reflect the fundamental principle that costs and benefits should be socialised. This is a requirement under the regulatory framework that WPD should observe if it implements islanding.

Cost savings for customers would be manifested in reductions to TUOS and DUOS. The requirements for socialised benefits means that, for islanding to be feasible, it must reduce WPD's overall cost base. This means that there should either be a reduction to DUOS and TUOS for all customers, or for a group of customers without negatively impacting any other customers. As such, reduction of use of system charges corresponds to real world cost reductions associated with avoided investment in network reinforcements.

It has not been possible to investigate the nature of the specific network reinforcement works that would be avoided through implementation of islands. It is proposed to consider the costs of typical reinforcements in the next stage of the project. However, for the purpose of this Feasibility Study analysis, the results of the NPV analysis have been provided for a range of factors applied to the DUOS and TUOS cost elements. These factors allow us to evaluate the feasibility of network islanding for a range of combined reductions in TUOS and DUOS (for customers in the island), and to make judgements about whether those reductions are realistic. The results of this analysis are presented in sub-section 3.4.1.

### 3.3.2 Representation of demand and generation profiles

Historic demand measurements were requested to be extracted from PowerON at identified locations, for example, the total demand of the Halfway substation is shown in Figure 3-2.

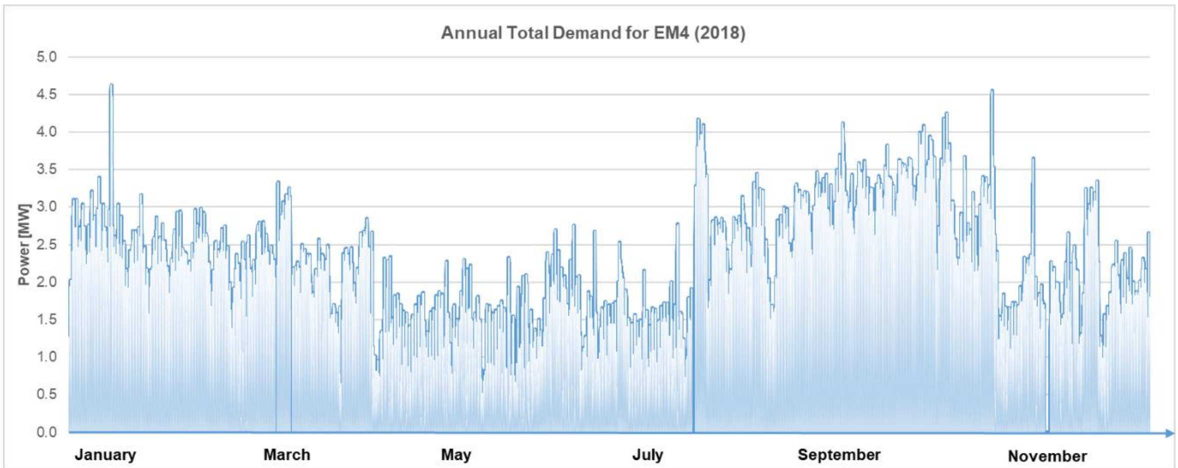


**Figure 3-2: Measured data for the annual total demand of Halfway (2018)**

For the purposes of the feasibility study, we have filtered the data for any obvious discrepancies (such as large spikes and periods with negative or zero demand measurements). The above figure is presented as an example for illustration, and includes the raw zero measurement values that are evident for Halfway. Please note that an alternative example is provided in Appendix C, for Harrold and Sharnbrook, where negative values are evident.

It should be noted that complete substation demand profiles can be used to improve techno-economic analysis of network islanding, however, the measured historic data could not be readily understood in their raw form.

There are a few methods to present generation or demand profiles to consider the relationship between demand and time. Here we propose the use of the concept of Load Duration Curve (LDC) to fill the gap in the analysis. An LDC is another term for a demand frequency distribution graph[6]. Such a curve presents the connection between time and demand, showing the percentage of time the load is greater or equal to a certain level (peak value)[7].

As such, LDCs are used to illustrate the changing behaviour of a power system over time, and the overall energy requirement corresponding to the changing demand level (since the analysis requires consideration of energy as opposed to solely peak demand that is the basis of planning for network infrastructure). They are valuable for making comparisons between different systems or groups within them by simplifying the chronological demand data into periods sorted from highest to lowest demand. It should be noted that LDCs can be derived for a range of time periods, i.e. periods sorted from highest to lowest demand within a single day, week, month, year etc. Depending on data availability, LDCs can also be derived for the aggregate system demand, or demand (or generation) for particular groups or feeders.

The following figures illustrate two different ways of thinking about LDCs to aid understanding. In Figure 3-3, the LDC is divided into vertical blocks (blue, orange and grey). These correspond to time periods separated by vertical lines through shoulder and knee points, which are shown at durations of 10% and 90% of the year for illustration, respectively (although these points are movable). The coloured blocks do not correspond to physical changes to the system, since the curve is no longer chronological, but are applied as theoretical constructs to derive the representative curve. As the system operates through each day it makes transitions between these operating blocks.

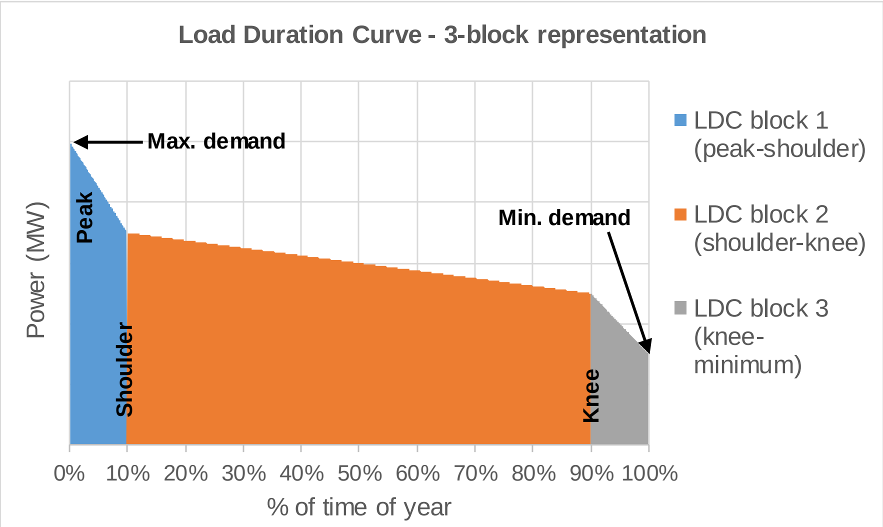


**Figure 3-3: Representative illustration of load duration curve (3-block representation)**

[6] "*Is there still merit in the merit order stack? The impact of dynamic constraints on optimal plant mix*" by Iain Staffell and Richard Green (Imperial College Business School, London)
[7] "*Load duration curve: A tool for technical-economic analysis of energy solution*" by A. Poulin, M. Dostie, M. Fournier and S. Sansreget.

Figure 3-4 shows the same curve divided into horizontal coloured blocks. Again, this does not correspond directly to physical changes to the system, but allows us to visualise the varying requirements for generation to meet the changing demand. The terms baseload, mid-merit and peak are applied to provide broad distinctions about how generators operate – corresponding to the economic modes of operation of different types of generation.

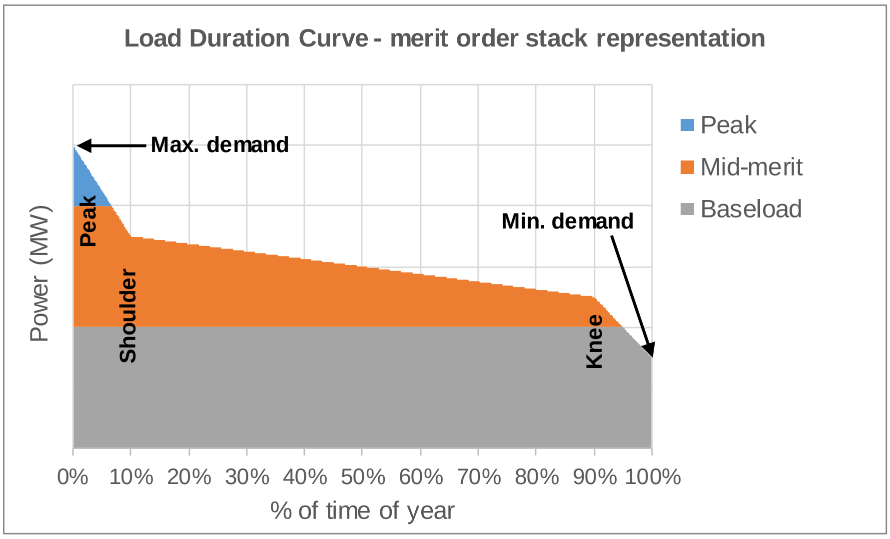


**Figure 3-4: Representative illustration of load duration curve (merit order stack representation)**

The LDC technique has been used to convert chronological demand data (load profiles from January to December) provided for identified locations into periods sorted from highest to lowest demand. A three-block LDC has then been adopted to represent the measured demand for comparison and analysis. An illustration of the LDC is shown below (in this case normalised, such that 100% on the x-axis corresponds to the whole year, 8,760 hours or 17,520 half-hour periods). It is to be noted that the area under that curve gives the total energy consumption of substations. Parameters for the points that represent the three load blocks (with straight line relationships between these points) have been determined from the data through calculation and visual inspection, as illustrated in Figure 3-3. An example of the comparison between the modelled substation demand and the total measured demand for Halfway substation is shown Figure 3-5 (blue and orange lines, respectively).

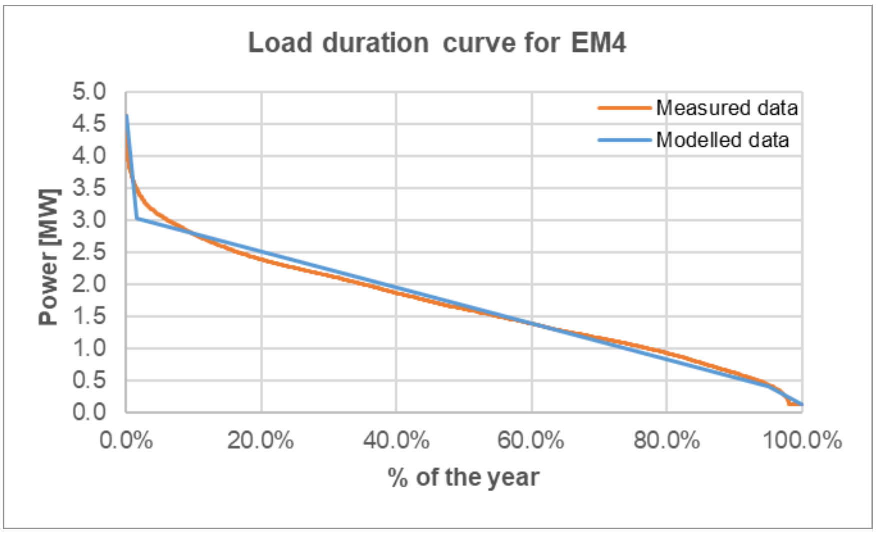


**Figure 3-5: Comparison between measured and modelled substation demand for EM4 (Halfway)**

It should be noted that:

- The measured data have been subjected to very limited filtering (removal of unrealistic spikes);
- No adjustment has been made for the substation demand at the time of system peak; and
- The number of customers within the island has been based on an assumed value of 2.5 kW per customer. The number of customers was required for calculation of the DUOS charges. More detailed analysis of customer numbers and types can be performed in the next stage of the project.

Historic generator output measurements have been converted to three-block LDCs in the same way as the demand measurements. The following figure shows the LDC used to model the output from the Holbrook (CHP) generator, with the LDC representing the total measured demand for Halfway substation plotted for reference. The measured generation output from the generator connected to Halfway has not been recorded correctly, and obtained data were unrealistic. The output from the Wykes Generator was used in this case as the generic generator scaled to the rated capacity of the generator located within the selected island (rated at 5.85 MW installed capacity). The LDC representing the scaled generator output is presented in Figure 3-6 and compared with demand at Halfway substation used in the feasibility assessment for this island.

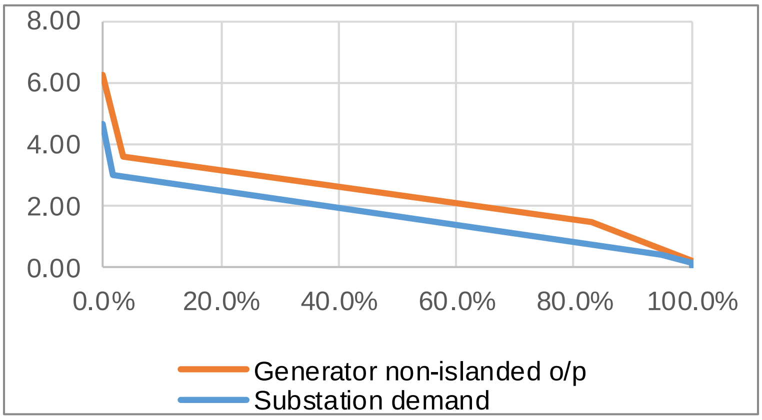


**Figure 3-6: Comparison of load duration curves for demand and generation for EM4**

It can be seen that the generator output exceeds the substation demand. It is envisaged that in the majority of cases implementation of network islands would result in curtailment of excess generation output to match the demand within the island. As such, the raw measured generation output is taken to be the non-island base case and compared with the case where the generation output is forced to match the island demand.

### 3.3.3 Calculation of net benefits

As discussed in sub-section 3.3.1, the financial benefits to customers from network islanding correspond to reductions to the TUOS and DUOS charges.

The net financial benefits correspond to the benefits minus the costs, which are discussed in sub-sections 3.2.2 to 3.2.4.

Finally, however, there is an additional cost item that must be considered in the calculation of the net benefits. This is the compensation to DG for lost revenue that is shown in the following formula used to calculate the net benefits of islanding:

$$\begin{matrix} Net \\ benefit \end{matrix} = \begin{matrix} TUOS \\ \&\, DUOS \\ reduction \end{matrix} - \begin{matrix} Compensation \\ to\ DG\ for \\ lost\ revenue \end{matrix} - \begin{matrix} Island \\ capex \end{matrix}$$

The effect of islanding requires the DG plant to reduce its output to match the demand within the island, and for other generation plant to increase their output to provide the additional power to the customers outside of the island. In order to implement the island, it is assumed that the overall cost of power consumed remains the same, on average. However, there is an additional requirement to maintain the revenue to the DG whose output is reduced. As such, the additional term is added to the formula for a compensation payment to the DG. This is illustrated in Figure 3-7.

The amount of the compensation payment is calculated with an additional percentage factor applied to the cost of the curtailed generation (calculated using the average wholesale price of 6.2p/kWh) to account for the net revenue after costs. The current working assumption for this factor is 10%, but sensitivity to this factor has been tested in the results presented in sub-section 3.4.1.

It should be noted that what DG are paid to generate does not necessarily cover all of the associated costs. Motivations for installing DG vary, but in many cases the principal objective is to improve security of supply of electricity (and heat) to the individual's site. The payments are dependent on specific contractual arrangements, which may be researched further in the next phase of the project, subject to details being available. It is expected that the agreement about prices would be subject to:

- Costs incurred by the DG, dependent on:
  - Technology (operational behaviour, efficiency, maintenance requirements);
  - Fuel prices;
  - Other drivers and contractual obligations (provision of electricity and/or heat for other purposes);
- Market forces determining contract prices from alternative generators to provide electricity to suppliers.

In the case of islanding for new developments, two additional terms are added to the net benefits formula, as follows:

$$\begin{matrix} Net \\ benefit \end{matrix} = \begin{matrix} TUOS \\ \&\, DUOS \\ reduction \end{matrix} + \begin{matrix} Other \\ opex \\ reduction \end{matrix} - \begin{matrix} Compensation \\ to\ DG\ for \\ lost\ revenue \end{matrix} - \begin{matrix} Island \\ capex \end{matrix} - \begin{matrix} New\ development \\ generator \\ capex \end{matrix}$$

The 'other opex reduction' corresponds to the cost of generation in the non-islanded base case minus the cost of generation from the generator that is developed as part of the new development in the island case.

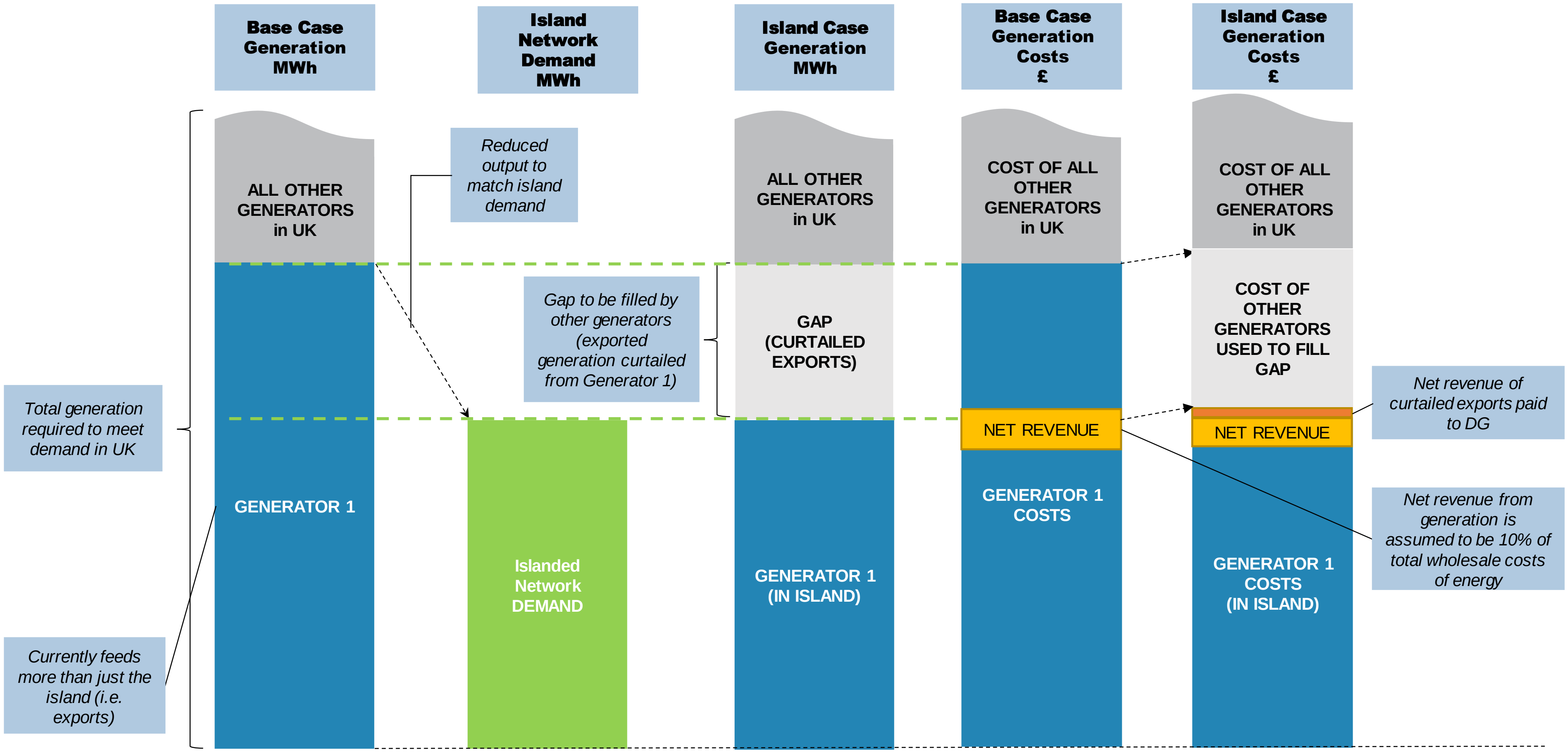


**Figure 3-7: Illustration of DG lost revenue**

## 3.4 Cost benefit analysis and investigation of the optimum scale of network islands

### 3.4.1 Cost benefit analysis for identified potential trial areas

This section presents the results of the NPV analysis for evaluation of the feasibility of network islanding. In each case, the island counterfactual case is compared with the corresponding non-islanded base case. The stream of annual capex and opex costs for each case is discounted according to the conventional method for calculating the NPV (with a 2019 reference year) and the following interest rates, taken from the Ofgem template for NIC submissions:

| Period | Interest rate |
|---|---|
| 2020-2028 | 3.5% |
| 2029-2039 | 3.0% |

The analysis is carried out based on the assumption that islanding solutions would be implemented in 2020 and have a lifetime of 20 years. As such, 20 years is taken to be the lifetime of the island solution that is broadly consistent with the lifetime of generation plant.

The full results of the NPV analysis are presented in sub-section 3.4.3, and a detailed worked example (for EM1) is presented in Appendix C for reference. A summary of the results is presented in Table 3-5, below, which shows the cumulative NPV in 2039 for each case based on fixed parameters for comparison, as follows:

- Factor applied to TUOS: 40%
- Factor applied to DUOS: 60%
- Factor applied to wholesale cost of curtailed generation for repayment to DG: 10%
- Factor for scaling generation capacity to MD (relevant to cases EM4 and ND1 where this scaling is applied to scale the generic generator and generator to be developed as part of the new development, respectively): 150%

**Table 3-5: Summary of NPV analysis results**

| | Summary of NPV analysis results for specified TUOS and DUOS reductions | | | | |
|---|---|---|---|---|---|
| Island | EM1 | EM2 | EM3 | EM4 | ND1 |
| Peak demand (MW) | 9.1 | 12.4 | 24.7 | 4.6 | 7.5 |
| Generator capacity (MW) | 25.0 | 25.0 | 20.9 | 5.9 | 11.3 |
| Cumulative NPV in 2039 (2019 £) | 82,449 | 3,979,757 | 17,288,972 | 1,596,951 | -8,996,102 |
| Factor applied to TUOS | 40% | 40% | 40% | 40% | 40% |
| Factor applied to DUOS | 60% | 60% | 60% | 60% | 60% |
| Factor applied to wholesale cost of curtailed generation for repayment to DG | 10% | 10% | 10% | 10% | 10% |
| Factor for scaling generation capacity to MD | - | - | - | 150% | 150% |

From this Feasibility Study analysis it is clear that curtailing the export of a generator to match the demand of an island can have a significant effect on the financial benefits. For example, islands EM1 and EM2 use the same generator, however, EM1 has a lower peak demand which requires the generator to be curtailed by an additional 3.3 MW during this half-hour period compared with EM2 (and in similarly throughout the year). This results in EM1 having much lower financial benefits compared with EM2.

In addition, EM3 is presented as an unusual case whereby the generation capacity is, in fact, insufficient to meet the peak demand of the island and the generator is operating to meet its obligations as a Short Term Operating Reserve (STOR) service provider. In practice it seems unlikely that this would be a feasible island due to these obligations on the generator. However, this case also illustrates (in the extreme) the point about the matching of the generator size with the peak demand of the island. In this case, the total demand is greater throughout the year, giving rise to greater values for the benefits through reduction of DUOS and TUOS. In the absence of generator curtailment (in fact its output would need to increase considerably), the effect of these benefits is to give a large cumulative NPV figure. Investigation of possible future trends in the provision of services such as STOR, and possible need for coordinated thinking about them, will be considered during the next stage of the project.

In the case of ND1, accounting for the full cost of implementing a CCGT CHP generator to support the island results in a large negative NPV figure. The cost of the investment is not outweighed by the benefits during the period of this analysis. However, other benefits and revenue streams for the generator will be explored during the next stage of the project to refine the Feasibility Study analysis.

### 3.4.2 Optimum scale of network islands to maximise benefits to customers

Although the results of EM1 and EM2 would indicate that financial benefits scale with the size of the island, this is not necessarily the case. EM4 for instance, is a much smaller island compared with EM1 but has sizeable financial benefits. Therefore, the analysis in the Feasibility Study has shown that assessing the viability of a network island is quite complex and a number of factors need to be carefully considered. The analysis has also shown that for the correct applications, network islanding could release significant financial benefits. By way of summary, the principal factors that have a combined effect on the feasibility of a network island include the following:

- Size of the island (number of customers, peak demand and annual energy demand);
- Available generation capacity;
- Current operating profile of the generator(s);
- Net revenue associated with any curtailed generation from the generator(s);
- Market and agreed contractual prices for energy; and
- Up-front capital costs for new equipment, in particular, the provision of a generator in the case of a New Development Island.

### 3.4.3 Full NPV analysis results

The cumulative NPV in 2039 (with a 2019 reference year) is presented in the following tables for each case. Two tables are presented for each potential island considered:

- Table 1 presents the cumulative NPV for each island for different combinations of scaling factors applied to TUOS and DUOS, respectively (0-100%, where a factor of 0% corresponds to a 100% reduction in the relevant charge such that it is zero for the islanded counterfactual case);
- Table 2:
  - In the case of islanding existing network where the analysis has been carried out using real data (EM1-EM3), this table presents the cumulative NPV for each island for

different combinations of scaling factors applied to the DUOS charges and the wholesale cost of curtailed generation for repayment to the generator(s);

– In the case of islanding existing network or new developments where the analysis has been carried out using scaled data for generic generator(s) and demand (EM4 and ND1), this table presents the cumulative NPV for each island for different combinations of scaling factors applied to the DUOS charges and the factor applied to scale the generation capacity to the peak demand (maximum demand, MD).

## EM1

| **Cumulative NPV in year 2039 (EM1)** | | **Factor applied to TUOS:** | | | | | |
|---|---|---|---|---|---|---|---|
| | | 0% | 20% | 40% | 60% | 80% | 100% |
| **Factor applied to DUOS:** | 0% | 5,692,789 | 5,312,083 | 4,931,378 | 4,550,672 | 4,169,967 | 3,789,261 |
| | 20% | 4,076,479 | 3,695,774 | 3,315,068 | 2,934,363 | 2,553,657 | 2,172,952 |
| | 40% | 2,460,170 | 2,079,464 | 1,698,759 | 1,318,053 | 937,348 | 556,642 |
| | 60% | 843,860 | 463,155 | 82,449 | -298,256 | -678,962 | -1,059,667 |
| | 80% | -772,449 | -1,153,155 | -1,533,860 | -1,914,566 | -2,295,271 | -2,675,977 |
| | 100% | -2,388,759 | -2,769,464 | -3,150,170 | -3,530,875 | -3,911,581 | -4,292,286 |

Factor applied to wholesale cost of curtailed generation for repayment to DG: 10%

| **Cumulative NPV in year 2039 (EM1)** | | **Factor applied to wholesale cost of curtailed generation for repayment to DG** | | | |
|---|---|---|---|---|---|
| | | 5% | 10% | 15% | 20% |
| **Factor applied to DUOS:** | 0% | 6,829,521 | 4,931,378 | 3,033,235 | 1,135,091 |
| | 20% | 5,213,211 | 3,315,068 | 1,416,925 | -481,218 |
| | 40% | 3,596,902 | 1,698,759 | -199,384 | -2,097,528 |
| | 60% | 1,980,592 | 82,449 | -1,815,694 | -3,713,837 |
| | 80% | 364,283 | -1,533,860 | -3,432,003 | -5,330,147 |
| | 100% | -1,252,027 | -3,150,170 | -5,048,313 | -6,946,456 |

TUOS factor: 40%

### EM2

| Cumulative NPV in year 2039 (EM2) | | Factor applied to TUOS: | | | | | |
|---|---|---|---|---|---|---|---|
| | | 0% | 20% | 40% | 60% | 80% | 100% |
| Factor applied to DUOS: | 0% | 12,903,755 | 12,389,288 | 11,874,822 | 11,360,355 | 10,845,888 | 10,331,421 |
| | 20% | 10,272,067 | 9,757,600 | 9,243,133 | 8,728,667 | 8,214,200 | 7,699,733 |
| | 40% | 7,640,379 | 7,125,912 | 6,611,445 | 6,096,978 | 5,582,511 | 5,068,045 |
| | 60% | 5,008,691 | 4,494,224 | 3,979,757 | 3,465,290 | 2,950,823 | 2,436,356 |
| | 80% | 2,377,002 | 1,862,536 | 1,348,069 | 833,602 | 319,135 | -195,332 |
| | 100% | -254,686 | -769,153 | -1,283,620 | -1,798,086 | -2,312,553 | -2,827,020 |

Factor applied to wholesale cost of curtailed generation for repayment to DG: 10%

| Cumulative NPV in year 2039 (EM2) | | Factor applied to wholesale cost of curtailed generation for repayment to DG | | | |
|---|---|---|---|---|---|
| | | 5% | 10% | 15% | 20% |
| Factor applied to DUOS: | 0% | 13,048,332 | 11,874,822 | 10,701,312 | 9,527,802 |
| | 20% | 10,416,643 | 9,243,133 | 8,069,623 | 6,896,113 |
| | 40% | 7,784,955 | 6,611,445 | 5,437,935 | 4,264,425 |
| | 60% | 5,153,267 | 3,979,757 | 2,806,247 | 1,632,737 |
| | 80% | 2,521,579 | 1,348,069 | 174,559 | -998,951 |
| | 100% | -110,110 | -1,283,620 | -2,457,130 | -3,630,640 |

TUOS factor: 40%

### EM3

| Cumulative NPV in year 2039 (EM3) | | Factor applied to TUOS: | | | | | |
|---|---|---|---|---|---|---|---|
| | | 0% | 20% | 40% | 60% | 80% | 100% |
| Factor applied to DUOS: | 0% | 40,599,703 | 39,581,059 | 38,562,415 | 37,543,770 | 36,525,126 | 35,506,482 |
| | 20% | 33,508,556 | 32,489,912 | 31,471,267 | 30,452,623 | 29,433,979 | 28,415,334 |
| | 40% | 26,417,409 | 25,398,764 | 24,380,120 | 23,361,476 | 22,342,831 | 21,324,187 |
| | 60% | 19,326,261 | 18,307,617 | 17,288,972 | 16,270,328 | 15,251,684 | 14,233,039 |
| | 80% | 12,235,114 | 11,216,469 | 10,197,825 | 9,179,181 | 8,160,536 | 7,141,892 |
| | 100% | 5,143,966 | 4,125,322 | 3,106,678 | 2,088,033 | 1,069,389 | 50,745 |

Factor applied to wholesale cost of curtailed generation for repayment to DG: 10%

| Cumulative NPV in year 2039 (EM3) | | Factor applied to wholesale cost of curtailed generation for repayment to DG | | | |
|---|---|---|---|---|---|
| | | 5% | 10% | 15% | 20% |
| Factor applied to DUOS: | 0% | 38,562,415 | 38,562,415 | 38,562,415 | 38,562,415 |
| | 20% | 31,471,267 | 31,471,267 | 31,471,267 | 31,471,267 |
| | 40% | 24,380,120 | 24,380,120 | 24,380,120 | 24,380,120 |
| | 60% | 17,288,972 | 17,288,972 | 17,288,972 | 17,288,972 |
| | 80% | 10,197,825 | 10,197,825 | 10,197,825 | 10,197,825 |
| | 100% | 3,106,678 | 3,106,678 | 3,106,678 | 3,106,678 |

TUOS factor: 40%

### EM4

| Cumulative NPV in year 2039 (EM4) | | Factor applied to TUOS: | | | | | |
|---|---|---|---|---|---|---|---|
| | | 0% | 20% | 40% | 60% | 80% | 100% |
| Factor applied to DUOS: | 0% | 4,883,941 | 4,688,443 | 4,492,946 | 4,297,448 | 4,101,951 | 3,906,454 |
| | 20% | 3,918,609 | 3,723,112 | 3,527,614 | 3,332,117 | 3,136,619 | 2,941,122 |
| | 40% | 2,953,277 | 2,757,780 | 2,562,282 | 2,366,785 | 2,171,288 | 1,975,790 |
| | 60% | 1,987,946 | 1,792,448 | 1,596,951 | 1,401,453 | 1,205,956 | 1,010,459 |
| | 80% | 1,022,614 | 827,117 | 631,619 | 436,122 | 240,624 | 45,127 |
| | 100% | 57,282 | -138,215 | -333,712 | -529,210 | -724,707 | -920,205 |

Factor applied to wholesale cost of curtailed generation for repayment to DG: 10%

Factor for scaling generation capacity to MD: 150%

| Cumulative NPV in year 2039 (EM4) | | Factor for scaling generation capacity to MD | | |
|---|---|---|---|---|
| | | 100% | 125% | 150% |
| Factor applied to DUOS: | 0% | 5,031,151 | 4,806,333 | 4,492,946 |
| | 20% | 4,065,819 | 3,841,001 | 3,527,614 |
| | 40% | 3,100,487 | 2,875,670 | 2,562,282 |
| | 60% | 2,135,156 | 1,910,338 | 1,596,951 |
| | 80% | 1,169,824 | 945,006 | 631,619 |
| | 100% | 204,492 | -20,325 | -333,712 |

TUOS factor: 40%

### ND1

| Cumulative NPV in year 2039 (ND1) | | Factor applied to TUOS: | | | | | |
|---|---|---|---|---|---|---|---|
| | | 0% | 20% | 40% | 60% | 80% | 100% |
| Factor applied to DUOS: | 0% | -3,590,864 | -3,899,544 | -4,208,225 | -4,516,905 | -4,825,585 | -5,134,265 |
| | 20% | -5,186,824 | -5,495,504 | -5,804,184 | -6,112,864 | -6,421,544 | -6,730,224 |
| | 40% | -6,782,783 | -7,091,463 | -7,400,143 | -7,708,823 | -8,017,503 | -8,326,183 |
| | 60% | -8,378,742 | -8,687,422 | -8,996,102 | -9,304,782 | -9,613,463 | -9,922,143 |
| | 80% | -9,974,701 | -10,283,381 | -10,592,062 | -10,900,742 | -11,209,422 | -11,518,102 |
| | 100% | -11,570,661 | -11,879,341 | -12,188,021 | -12,496,701 | -12,805,381 | -13,114,061 |

Factor applied to wholesale cost of curtailed generation for repayment to DG: 10%

Factor for scaling generation capacity to MD: 150%

| Cumulative NPV in year 2039 (ND1) | | Factor for scaling generation capacity to MD | | |
|---|---|---|---|---|
| | | 100% | 125% | 150% |
| Factor applied to DUOS: | 0% | 499,772 | -1,854,226 | -4,208,225 |
| | 20% | -1,096,188 | -3,450,186 | -5,804,184 |
| | 40% | -2,692,147 | -5,046,145 | -7,400,143 |
| | 60% | -4,288,106 | -6,642,104 | -8,996,102 |
| | 80% | -5,884,065 | -8,238,063 | -10,592,062 |
| | 100% | -7,480,025 | -9,834,023 | -12,188,021 |

TUOS factor: 40%

## 3.5 Further high level review

### 3.5.1 High level review of legal, regulatory and commercial arrangements related network islanding

As indicated in the High Level Research and Analysis Report, network islanding would require that regulatory and commercial frameworks should become more flexible and be able to accommodate and respond to energy system changes. Currently, the commercial and contractual frameworks (see Figure 3-8) do not offer a great deal of flexibility to develop and trial innovative business models, which could be necessary to enable network islanding arrangements. Many of the issues have already been raised with Ofgem, in particular in the areas of grid connection, flexible services and future retail regulations.

The yellow lines in Figure 3-8 represent the power flow through the system. The green lines correspond to the flow of payments.

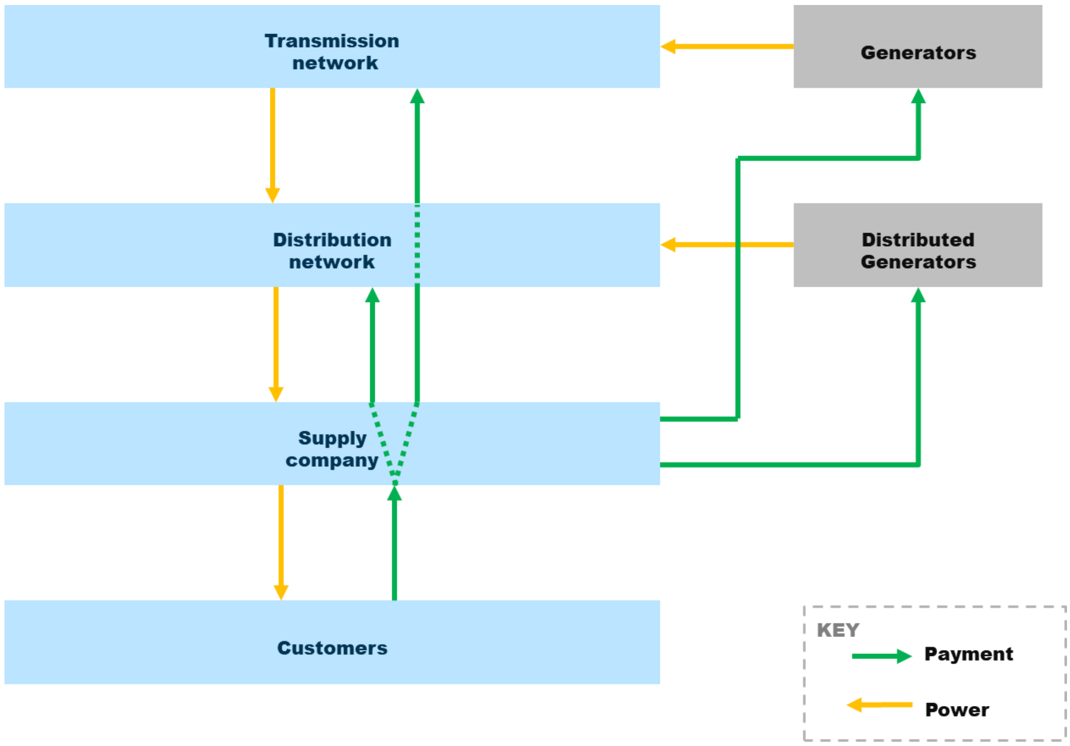


**Figure 3-8: Centralised energy market with key parties and activities in electricity industry**

The low carbon energy transition, decentralisation and rapid technological advancement have initiated thinking about development of Non-Traditional Business Models (NTBM) to support transformation within the sector in the form of an Ofgem consultation[8]. NTBM can be understood as business models offering new products, services or new ways of delivering these, that are different to those traditionally provided in the existing energy market. Those services could offer solutions to overcome issues relating to diverse motivations, ownership and scale of operation of different market participants.

At present, individual consumers each have a contractual relationship with a single supplier, which contracts in turn with various generators or DG. Power is delivered from the generators to the customers through the physical transmission and distribution networks, as indicated in Figure 3-9. The costs incurred by the transmission and distribution companies to develop and operate their networks are recovered through use of network charges (separate for transmission and distribution networks) collected by the supply companies and passed through.

In the islanded arrangement, adjustments would need to be made to accommodate changes to dispatch of the generators inside and outside of the islands. This affects the contractual arrangements between supply companies and generators. The present relationships between existing customers and supply companies also need to be considered if a dedicated supply company or service company is required for islanded customers.

[8] "*Non-traditional business models: Supporting transformative change in the energy market – Discussion Paper*" by Ofgem (25 February 2015), https://www.ofgem.gov.uk/sites/default/files/docs/2015/02/non-traditional_business_models_discussion_paper_0.pdf

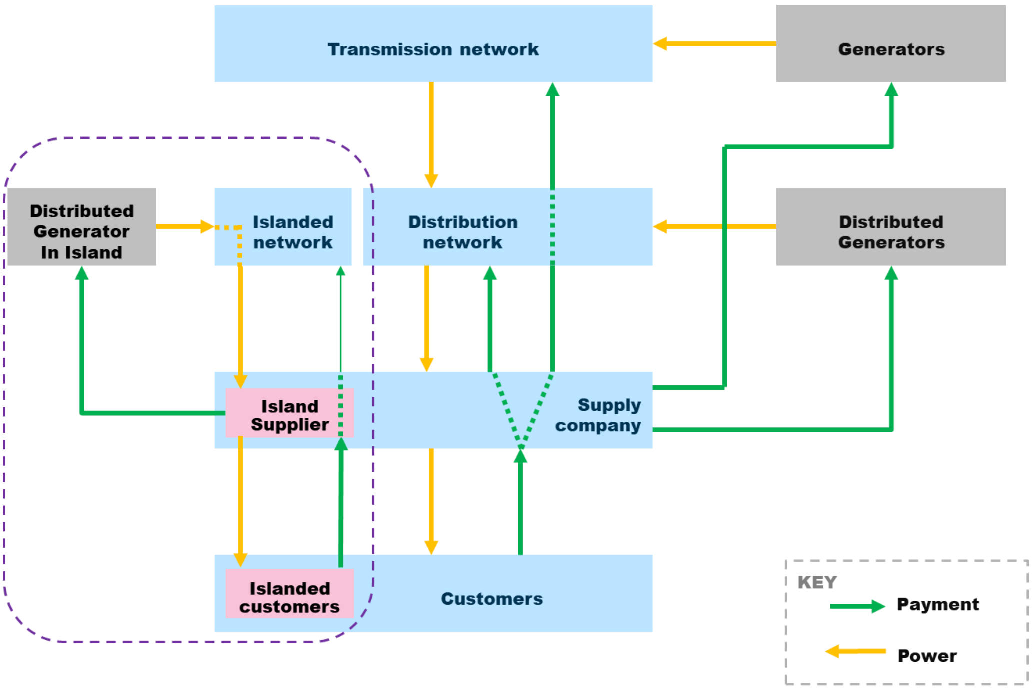


**Figure 3-9: NTBM to accommodate network islanding in the centralised energy market**

Future arrangements that may be applicable to sale of generation from DG in network islands, served by third-party suppliers or through "self-supply", could take the form of:

- **Customers served by third-party suppliers**
  - **Licence lite model** – this arrangement allows distributed generators to act as licensed suppliers without becoming participants in industry codes. However, licence lite suppliers have to partner with existing fully-licensed suppliers, who participate in industry codes on their behalf. The main interactions between customers, generators and suppliers are presented in Figure 3-10.

    Therefore, direct supply of generation to local customers by licence lite suppliers could enable cheaper energy to be provided to those customers without the cost burden of setting up as fully-licensed suppliers.

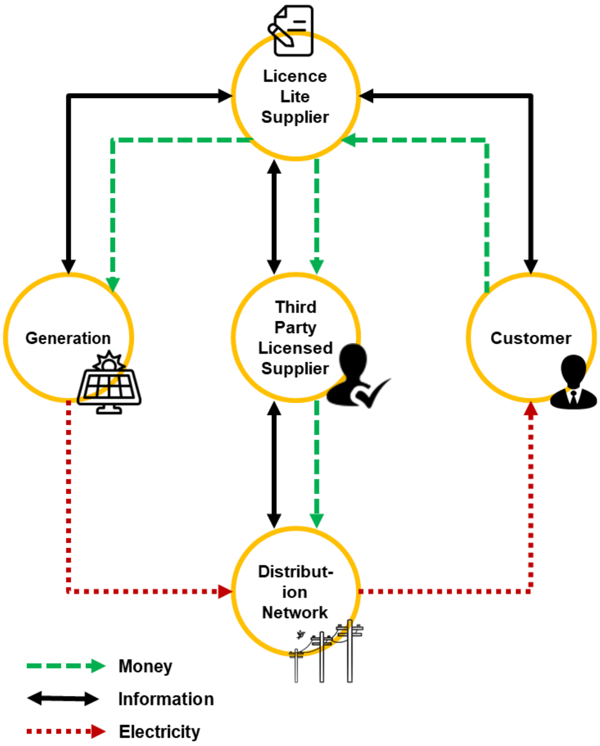


**Figure 3-10: Illustration of interaction between parties in case of Licence Lite Supplier arrangement[9]**

- **Licence exempt** – this arrangement could allow small licence-exempt suppliers to be established to provide electricity to customers that they have generated themselves up to 5 MW in total, of which no more than 2.5 MW can be supplied to domestic customers (around 500 customers). The licence exempt supplier 'is required to have a contractual arrangement with an existing licensed supplier, as they deliver and sell their power over the public network and may need their power to be topped-up when they are not generating enough'[10].
- **Energy Service Company (ESCo)** – under this arrangement a company is established to 'provide energy services, such as hot water, heating, lighting or energy efficiency saving, as opposed to the direct supply of electricity or gas'. However, 'if they are directly supplying electricity, they will need to partner with a licensed supplier or set up a private wire'.
- **White Label** – under this arrangement, 'a white label supplier works in partnership with a licensed supplier to offer tariffs under a different brand. The white label supplier negotiates their own tariff and can therefore shape it to meet their own objectives… [such as] investing in local energy efficiency measures or developing its own generation'. However, they do not supply energy directly (this is done by the licensed supplier) and they cannot set the price for their own generation. Some licensed suppliers are prepared to engage in sleeving combined as part of the arrangements with white label suppliers.

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[9] "*Licence Lite': proposed updates to the SLC 11.3 operating guidance"* by Ofgem (10 October 2014) https://www.ofgem.gov.uk/publications-and-updates/licence-lite-proposed-revisions-slc-11-3-operating-guidance

[10] *"Local Supply: Options for selling your energy locally (2nd edition)*" by Stephens Scown and Regen SW (March 2016) https://www.regen.co.uk/publications/local-supply-options-for-selling-your-energy-locally-2nd-edition/

- **Local Tariffs** – under this arrangement, suppliers can 'offer local tariffs that are linked to a local generation site… This approach can be effective at building local support for a project and help people make the link between local generation and their own consumption… However, the tariffs need to be subsidised in part by generator in order to keep price low, which could mean a reduction in profits for the stakeholders'.
- **Sleeving/Third party netting** – this arrangement 'is a variant of a standard Power Purchase Agreement (PPA) between a licensed supplier and generator and serves the purpose of linking the generation to the customer. This allows the customer to purchase energy directly from the generating plant via a licensed supplier, which manages the imbalance risk'.

- **"Self-supply"**
  - **Fully licensed supplier** – under this arrangement, a full supply licence could be obtained to provide 'full control over the purchasing and retail of electricity'. It is required that the supplier 'must comply with a number of industry codes and commitments', which involves high costs to set up. Therefore, this arrangement could be most beneficial to larger generation projects (+100MW), for which there may also be a requirement for a generation licence.
  - **Private wire** – under this arrangement, 'private wire agreements essentially allow a generator to sell power to neighbouring premises without transmitting through the public network'. However, the arrangement 'requires significant capital investment in the private wire network', a legal contract and a 'guarantee that demand will remain over lifetime of generation plant'.

At present, a number of challenges relating to flexibility services have been identified and many NTBMs are still developing to provide new regulatory and commercial arrangements that accommodate these challenges and mitigate negative implications for customers. However, it is generally expected that network islanding, smart grid development and demand-side response will provide overall benefits through suitable commercial arrangements.

### 3.5.2 High level review of the requirements for stakeholder engagement

Stakeholder engagement represents a critical success factor for the next phase of this project. Engagement with these stakeholders will help to demonstrate that islanding is not only feasible, but may be practically implemented on WPD's network.

An outline stakeholder engagement plan will be developed in the early stages of the next phase indicating who should be engaged and by what means (direct email or letter, website, electronic newsletter, media, public meetings etc). The plan will seek to identify relevant stakeholders that could be affected by network islanding and who would be likely to provide value in terms of addressing areas those areas that require investigation. It is anticipated that the stakeholders to be engaged may include:

- Ofgem;
- Elexon;
- National Grid ESO;
- Owners of DG;
- Suppliers;
- Local businesses; and
- Residential customers.

# 4. Conclusions

## 4.1 Findings

The Feasibility Study has followed on from previous work comprising literature reviews, data gathering, high level review, research and analysis. This initial work as part of the Network Islanding Investigation project found that network islanding was both technically and commercially feasible and could provide opportunities for financial and carbon savings compared with the non-islanded case.

The work carried out for the Feasibility Study aimed to understand, in more detail, how potential network islands can be identified and evaluate the range of financial benefits that could be realised through adopting a network islanding approach.

Most importantly, the results of the Feasibility Study have highlighted that adopting network islanding on parts of WPD's 33kV distribution network could achieve significant financial benefits. Although the findings from this task are based on engineering assumptions (in the presence of missing information/data) it is a positive step forward for the Network Islanding Investigation project.

The work for the Feasibility Study has generated a number of important learning points that need to be considered when selecting potential islands and assessing the expected financial benefits. A summary of these points is provided below:

- Provision of accurate data – a clear understanding of the demand and generation within a network island is important as it directly informs the ongoing opex of the island. During the Feasibility Study a number of potential islands had to be disregarded as insufficient data was available.
- Network configuration – detailed analysis has to be performed on the surrounding network to understand the capex investment required to facilitate the network island. The Feasibility Study required an assessment of the circuit breakers, control system and ancillary equipment required to facilitate the network island.
- Data Sources – a number of different data sources are required to assess the financial benefits of the network island. For example, calculation of cash flow for the network island requires information on: standard/site-specific DUOS, TUOS, wholesale price of energy, generator operating costs, customer numbers, etc.

Therefore, the assessment and calculation of financial benefits for a network island are complex. It is important to note that the assessment in the Feasibility Study has aimed to use verified data wherever possible. However, a number of engineering assumptions have been made where data wasn't readily available or published. The results from the Feasibility Study are sensitive to these assumptions, which have been highlighted in this report, however, the high level benefits are expected to still be valid.

Another important aspect that was discovered during the Feasibility Study was that financial benefits do not necessarily scale with the size of the island. In fact, a number of factors need to be considered to understand the financial benefits of a network island that include:

- Size of the island (number of customers, peak demand and annual energy demand);
- Available generation capacity;
- Current operating profile of the generator(s);
- Net revenue associated with any curtailed generation from the generator(s);

- Capital cost of new equipment for the new developments especially (these include the capital cost of a generating unit); and
- Market and agreed contractual prices for energy.

## 4.2 Next steps

The output from the Feasibility Study will be used as a basis for the next stages of the Network Islanding Investigation project.

A high level overview of the activities associated with the next stage of the project is given as follows:

- Acquire network models for selected areas from the Feasibility Study and assess their suitability to be used for power system studies;
- Obtain detailed generator information including electrical characteristics, connection arrangement, control system and operational data;
- Obtain detailed information of surrounding network and protection schemes;
- Run a series of power system studies to understand the technical behaviour of the network islands under a range of operational scenarios;
- Further investigation of the specific technologies and costs thereof for implementing network islanding;
- Review of developments relating to the transition to DSO, including Ofgem and Elexon activities concerning the regulatory and commercial frameworks for ownership of equipment and development of new business models; and
- Further refinement of the benefits associated with network islanding.

The deliverables from the next stage will be shared as they are completed with a summary of all the outcomes to be presented in the Investigation Findings Report.

# Appendix A
Trial areas – supporting material

# Appendix A - Trial areas – supporting material

### Identified potential islands

The following diagrams are annotated copies of the system diagrams provided from the PowerOn system operated by WPD. They show the extent of the potential islands identified that are referenced in the Feasibility Study report, and used to determine the equipment required to implement each island.

The islands identified are as follows:

| Island ID | Location |
|---|---|
| EM1 | Wykes Generation (CHP) feeding Sharnbrook and Harrold, near Wellingborough – peak demand of 9.1 MW |
| EM2 | Wykes Generation (CHP) feeding Little Irchester, near Wellingborough – peak demand of 12.4 MW |
| EM3 | Redfield Road STOR feeding Wollaton Road, near Nottingham – peak demand 24.7 MW |
| EM4 | Holbrook CHP (represented by scaled, generic data) feeding Halfway, near Sheffield – peak demand of 4.6 MW |
| ND1 | New 3,000 home development, associated commercial units and 11.25MW CHP – peak demand 7.5MW |

### Wellingborough (EM1-EM2)

| East Midlands – existing network | Goosey Lodge, Wymington, Rushden | | | | |
|---|---|---|---|---|---|
| **Network** | **Generation** | **Network Demand** | | | |
| **GSP:** Grendon 132kV S STN (670007)<br><br>**BSP:** Wellingborough 33kV (940011)<br><br>**Substation:** Wykes Generation 33kV S STN (920010) | **Export Capacity:** 25MW<br><br>**Technology:** Medium CHP<br><br>**Voltage level:** 33kV | **Substation / Transformer** | **Node** | **Substation peak demand (MVA)** | **Forecast load in 2022/2023 (MVA)** |
| | | Sharnbrook 33 11 | SHAR5J | 5.6 | 4.6 |
| | | Little Irchester | LITI5J | 14.8 | 14.0 |
| | | Harrold | HARR5J | 1.50 | 1.96 |

**Notes**

- Average generator output from analogues measurement are in range between 10-15 MW.
- Island Boundary includes steps:
  - Open CB01 at 926264 Higham Ferrers Switching Station
  - Open 43E0520 Cringle House PMR
  - Open Wellingborough 33kV CB06
- Additional data request for MW analogues:
  - Harrold 33/11kV (T1)
  - Wellingborough 132/11 GT1A and GT2A
  - Denton 33/11kV T2
  - Brackmills 33/11kV T1 & T2
  - Park Farm 33/11kV T1 & T2
  - Cannon Street 33/11kV T1 & T2

### Sharnbrook substation

Rural residential village setting, next to a small business park and golf course.


**Figure A 1: Sharnbrook 33 11 kV S Stn**

### Harrold substation

Rural village setting, residential/commercial area.


**Figure A 2: Harrold 33 11 kV S Stn**

### Little Irchester

Rural large village setting, residential and industrial area.


**Figure A 3: Little Irchester 33 11 kV S Stn**

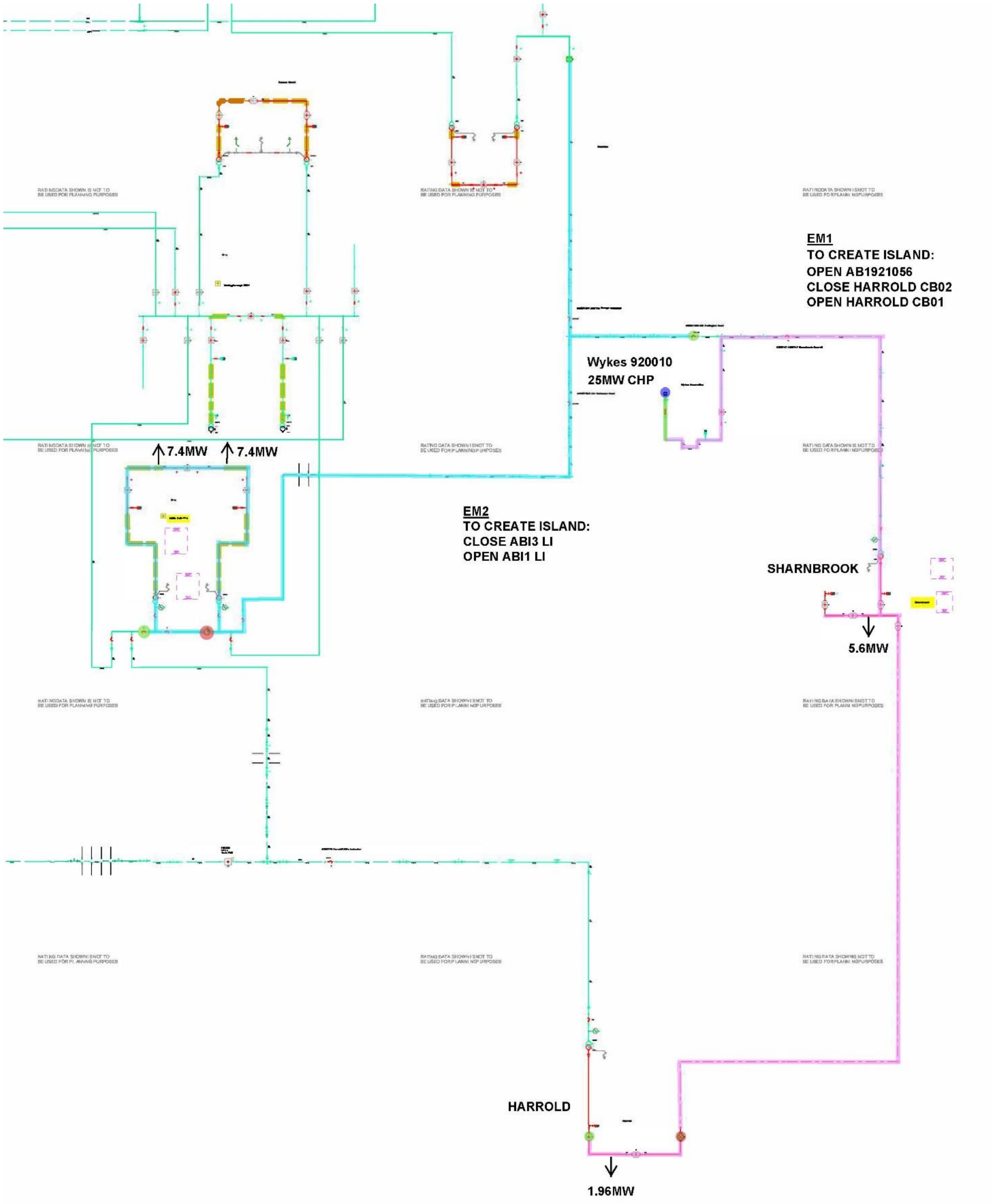



**Figure A 4: EMU/Power On diagram with highlighted proposed boundary of the islands EM1 and EM2**

### Nottingham (EM3)

| East Midlands | Nottingham | | | | | |
|---|---|---|---|---|---|---|
| **Network** | **Generation** | **Network Demand** | | | | |
| **GSP:** Ratcliffe on Soar 132 kV S STN (680002)<br><br>**BSP:** Nottingham 33kV S STN (880003)<br><br>**Substation:** Redfield Road 1 STOR (883447) | **Redfield Road 1 STOR, Nottingham**<br><br>**Export Capacity:** 20.88MW<br><br>**Technology:** Biomass & Energy Crops (not CHP)<br><br>**Voltage level:** 33kV | **Substation / Transformer** | **Node** | **Substation peak demand (MVA)** | **Forecast load in 2022/2023 (MVA)** |
| | | Wollaton Road 11kV | WOLR5J | 22.5 | 19.1 |

**Notes**

- Island boundary includes step:
  - Open Nottingham 33kV CB05 and 33kV CB39
- Additional request for analogue measurement include Talbot Street T1 & T2
- The selected generator operates under a Short Term Operating Reserve (STOR) contract with National Grid. The feasibility of running this generator to support an island needs to be investigated further. It could be possible that STOR generator could not be able to be islanded.

### Wollaton Road

Suburban setting. Residential/industrial area.


**Figure A 5: Wollaton Road 33/11 kV**

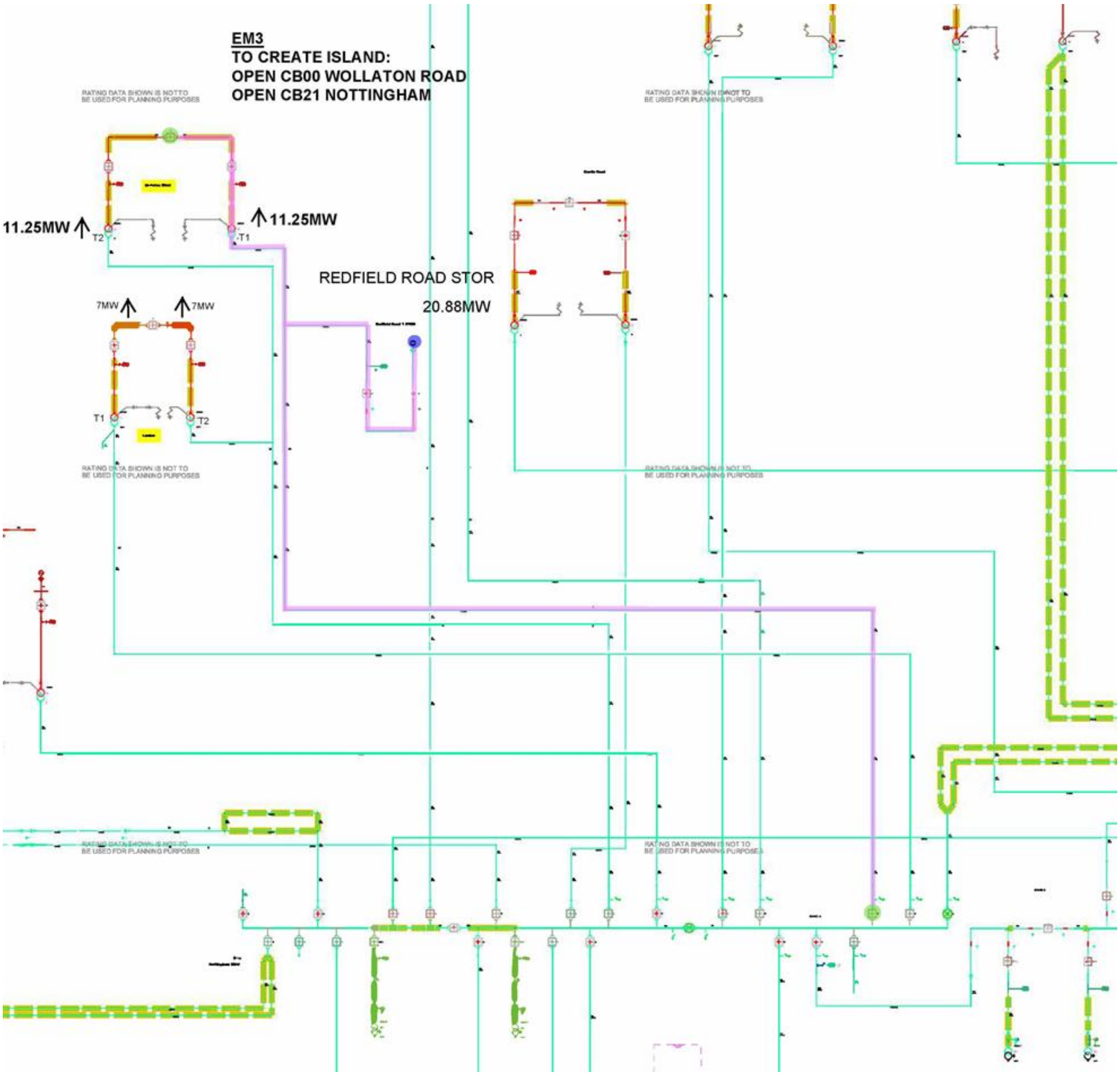



Figure A 6: EMU/Power On diagram with highlighted proposed boundary of the island EM3

### Halfway, Sheffield (EM4)

| Network | Generation | Network Demand | | | |
|---|---|---|---|---|---|
| | | **Substation / Transformer** | **Node** | **Substation peak demand (MVA)** | **Forecast load in 2022/2023 (MVA)** |
| **GSP:** Chesterfield 132kV S STN (680007)<br><br>**BSP:** Whitwell 33kV S STN (890009)<br><br>**Substation:** Halfway 33 11 kV S STN (890089) | **Holbrook CHP**<br>**Export Capacity:** 5.85 MW<br>**Technology:** Medium CHP<br><br>**Morrisons Halfway**<br>**Export Capacity:** 0.85 MW<br>**Technology:** Mini CHP<br><br>**Voltage level:** 11kV | Halfway (TA) | HALF5J | 3.3 | 2.7 |

**Notes**

- Generator MW analogues measurements for Morrisons Halfway Mini CHP is missing.
- Island can be created with all network downstream of 11kV busbar A at Halfway Primary. This could be include busbar B depending on analysis in feasibility study.
- Ratio of demand and generation is coherent with principles set in the methodology.

Suburban district setting. Large residential area, next to an industrial estate.


**Figure A 7: Halfway 33 11 kV S Stn**

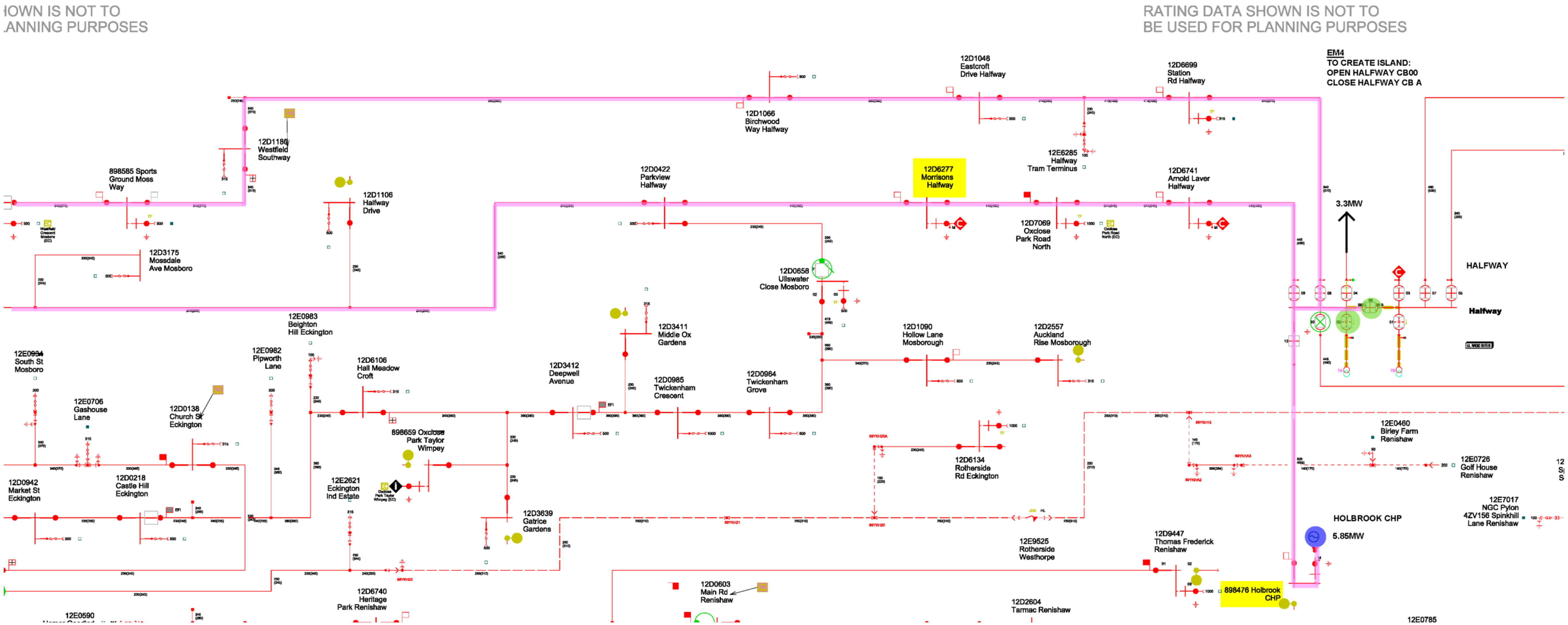



**Figure A 8: EMU/Power On diagram with highlighted proposed boundary of the island EM4**

# Appendix B
Schedule of WPD (EMID) DUOS Charges

# **Appendix B** – Schedule of WPD (EMID) DUOS Charges

**Western Power Distribution (East Midlands) plc - Effective from 1 April 2020 - Final LV and HV charges**

**Time Bands for Half Hourly Metered Properties**

| Time periods | Red Time Band | Amber Time Band | Green Time Band |
|---|---|---|---|
| Monday to Friday | 16:00 to 19:00 | 07:30 to 16:00<br>19:00 to 21:00 | 00:00 to 07:30<br>21:00 to 24:00 |
| Weekends | | | 00:00 to 24:00 |
| Notes | All the above times are in UK Clock time | | |

**Time Bands for Half Hourly Unmetered Properties**

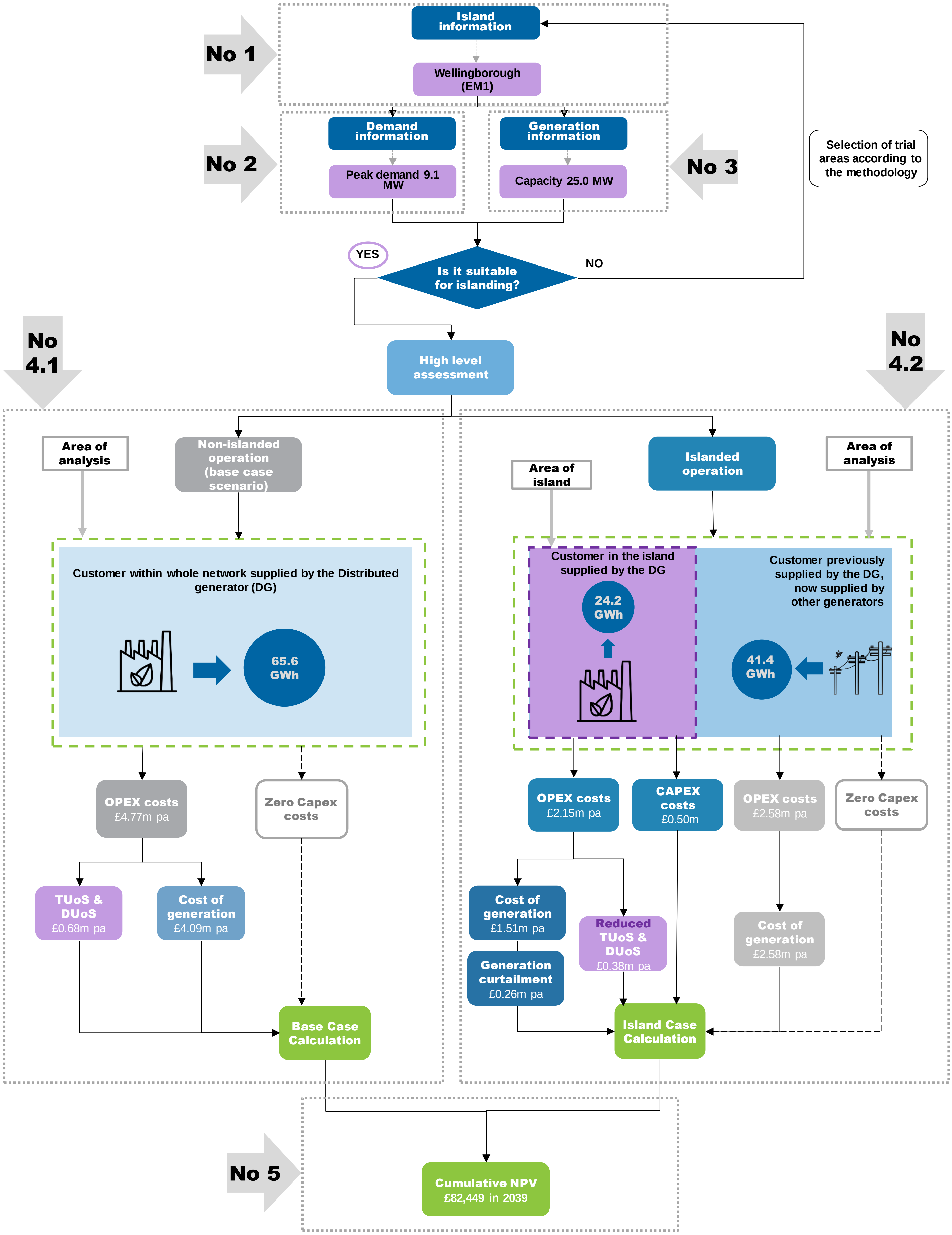
| | Black Time Band | Yellow Time Band | Green Time Band |
|---|---|---|---|
| Monday to Friday Nov to Feb | 16:00 to 19:00 | 07:30 to 16:00<br>19:00 to 21:00 | 00:00 to 07:30<br>21:00 to 24:00 |
| Monday to Friday Mar to Oct | | 07:30 to 21:00 | 00:00 to 07:30<br>21:00 to 24:00 |
| Weekends | | | 00:00 to 24:00 |
| Notes | All the above times are in UK Clock time | | |

| Tariff name | Open LLFCs | PCs | Unit charge 1 (NHH) or red/black charge (HH) p/kWh | Unit charge 2 (NHH) or amber/yellow charge (HH) p/kWh | Green charge(HH) p/kWh | Fixed charge p/MPAN/day | Capacity charge p/kVA/day | Exceeded capacity charge p/kVA/day | Reactive power charge p/kVArh | Closed LLFCs |
|---|---|---|---|---|---|---|---|---|---|---|
| Domestic Unrestricted | 1 | 1 | 2.085 | | | 3.35 | | | | 2 |
| Domestic Two Rate | 3 | 2 | 2.339 | 0.834 | | 3.35 | | | | 4, 8, 10 |
| Domestic Off Peak (related MPAN) | 11 | 2 | 1.203 | | | | | | | |
| Small Non Domestic Unrestricted | 13 | 3 | 1.959 | | | 6.64 | | | | 22, 34, 43 |
| Small Non Domestic Two Rate | 37 | 4 | 2.116 | 0.830 | | 6.64 | | | | 16, 19, 28, 31, 49, 52 |
| Small Non Domestic Off Peak (related MPAN) | 901 | 4 | 0.986 | | | | | | | |
| LV Medium Non-Domestic | 81 | 5-8 | 2.048 | 0.825 | | 24.94 | | | | 83, 85 |
| LV Sub Medium Non-Domestic | 80 | 5-8 | 1.637 | 0.810 | | 4.28 | | | | |
| LV Network Domestic | 246 | | 8.226 | 1.610 | 0.832 | 3.35 | | | | |
| LV Network Non-Domestic Non-CT | 247 | | 7.703 | 1.551 | 0.828 | 6.64 | | | | |
| LV HH Metered | 58, 990 | | 5.719 | 1.310 | 0.813 | 9.96 | 2.76 | 5.79 | 0.146 | |
| LV Sub HH Metered | 59 | | 4.321 | 1.127 | 0.800 | 7.77 | 3.44 | 5.34 | 0.101 | |
| HV HH Metered | 60, 991 | | 2.908 | 0.955 | 0.789 | 71.75 | 4.20 | 6.22 | 0.053 | 929 |
| NHH UMS category A | 800 | 8 | 2.353 | | | | | | | |
| NHH UMS category B | 801 | 1 | 2.585 | | | | | | | |
| NHH UMS category C | 802 | 1 | 3.487 | | | | | | | |
| NHH UMS category D | 803 | 1 | 2.119 | | | | | | | |
| LV UMS (Pseudo HH Metered) | 804 | | 21.200 | 2.185 | 1.531 | | | | | |
| LV Generation NHH or Aggregate HH | 986 | 8&0 | -0.628 | | | | | | | |
| LV Sub Generation NHH | 970 | 8 | -0.548 | | | | | | | |
| LV Generation Intermittent | 971 | | -0.628 | | | | | | 0.140 | |
| LV Generation Intermittent no RP charge | 141 | | -0.628 | | | | | | | |
| LV Generation Non-Intermittent | 973 | | -4.896 | -0.545 | -0.033 | | | | 0.140 | |
| LV Generation Non-Intermittent no RP charge | 142 | | -4.896 | -0.545 | -0.033 | | | | | |
| LV Sub Generation Intermittent | 972 | | -0.548 | | | | | | 0.119 | |
| LV Sub Generation Intermittent no RP charge | 143 | | -0.548 | | | | | | | |
| LV Sub Generation Non-Intermittent | 974 | | -4.306 | -0.468 | -0.028 | | | | 0.119 | |
| LV Sub Generation Non-Intermittent no RP charge | 144 | | -4.306 | -0.468 | -0.028 | | | | | |
| HV Generation Intermittent | 975 | | -0.343 | | | 44.91 | | | 0.095 | |
| HV Generation Intermittent no RP charge | 145 | | -0.343 | | | 44.91 | | | | |
| HV Generation Non-Intermittent | 977 | | -2.809 | -0.267 | -0.014 | 44.91 | | | 0.095 | |
| HV Generation Non-Intermittent no RP charge | 146 | | -2.809 | -0.267 | -0.014 | 44.91 | | | | |

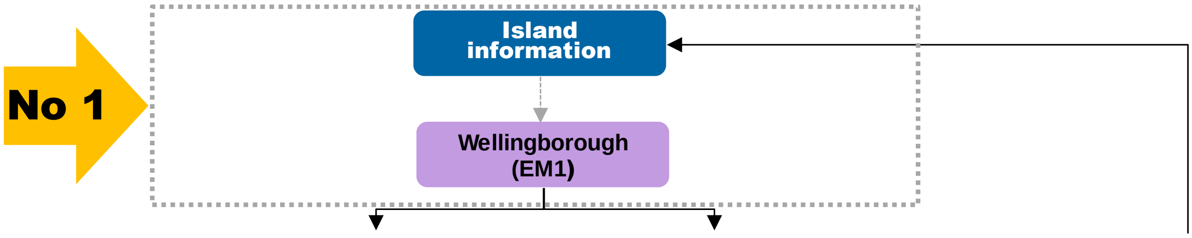
# Appendix C
Feasibility Study analysis worked example – EM1

# **Appendix C** - Feasibility Study analysis worked example – EM1

This appendix reproduces information from the main report and earlier appendices in order to illustrate the calculation steps implemented in the feasibility study assessment spreadsheet.



## C1) Island information




Potential trial areas (and switching arrangements) identified from EMU/PowerOn diagrams.

### EM1 – Wellingborough (East Midlands)

**Table C 1: EM1 island description**

| Wellingborough - East Midlands – existing network | | | | | |
|---|---|---|---|---|---|
| **Generation** | | **Demand** | | | |
| **Goosey Lodge, Wymington, Rushden** | **Network** | **Substation / Transformer** | **Node** | **Substation peak demand (MVA)** | **Forecast load in 2022/2023 (MVA)** |
| **Export Capacity:** 25.0 MW | **GSP:** Grendon 132kV S STN (670007) | **Sharnbrook 33 11** | SHAR5J | 5.60 | 4.60 |
| **Technology:** Medium CHP | **BSP:** Wellingborough 33kV (940011) | **Harrold 33 11** | HARR5J | 1.50 | 1.96 |
| **Substation:** Wykes Generation 33kV S STN (920010) | | | | | |

*Sharnbrook substation*

Rural residential village setting, next to a small business park and golf course.


**Figure C 1: Sharnbrook 33 11 kV S Stn**

### *Harrold substation*

Rural village setting, residential/commercial area.


**Figure C 2: Harrold 33 11 kV S Stn**

Potential trial EM1 area (Sharnbrook and Harrold) highlighted in pink on the EMU/PowerOn diagrams.

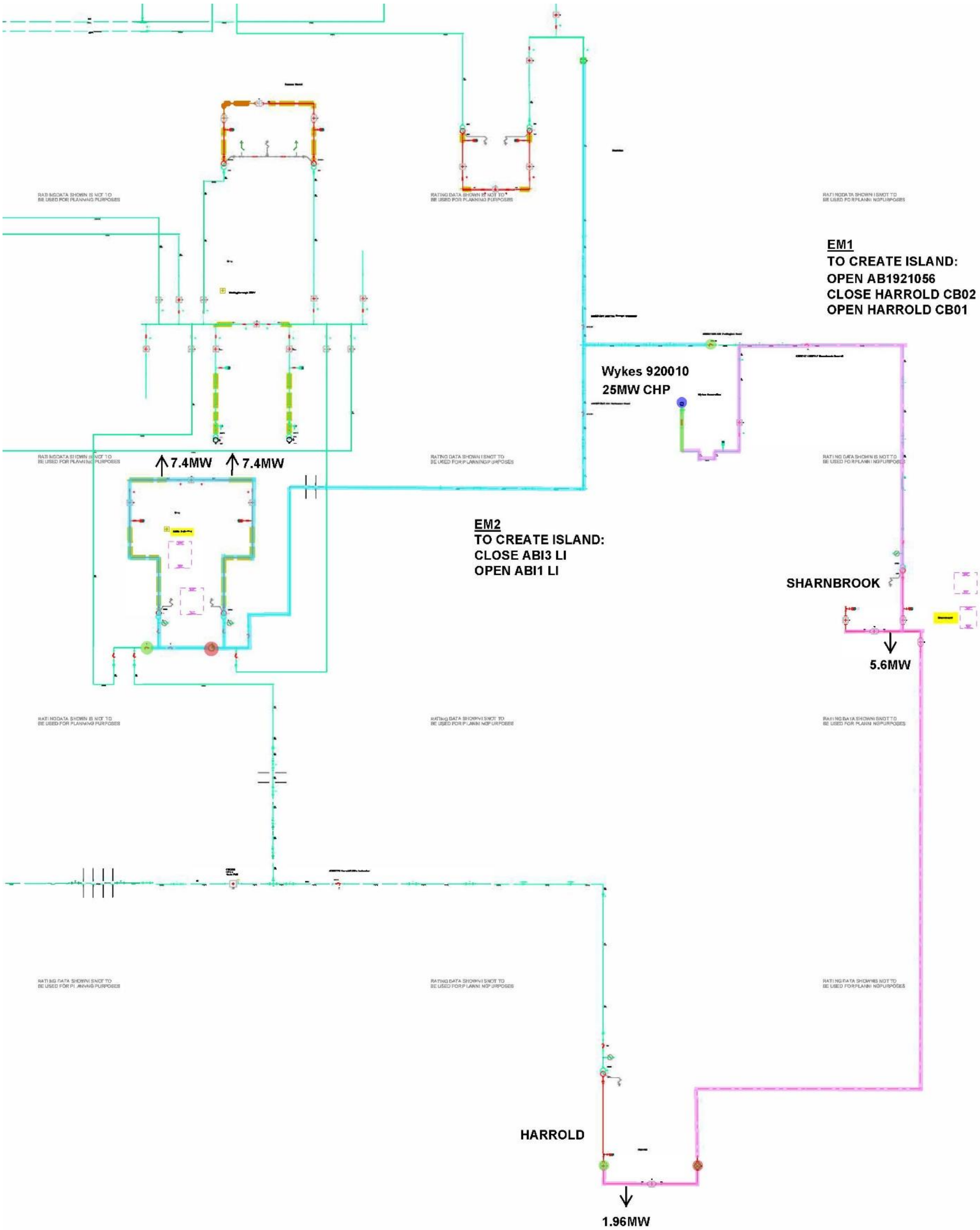
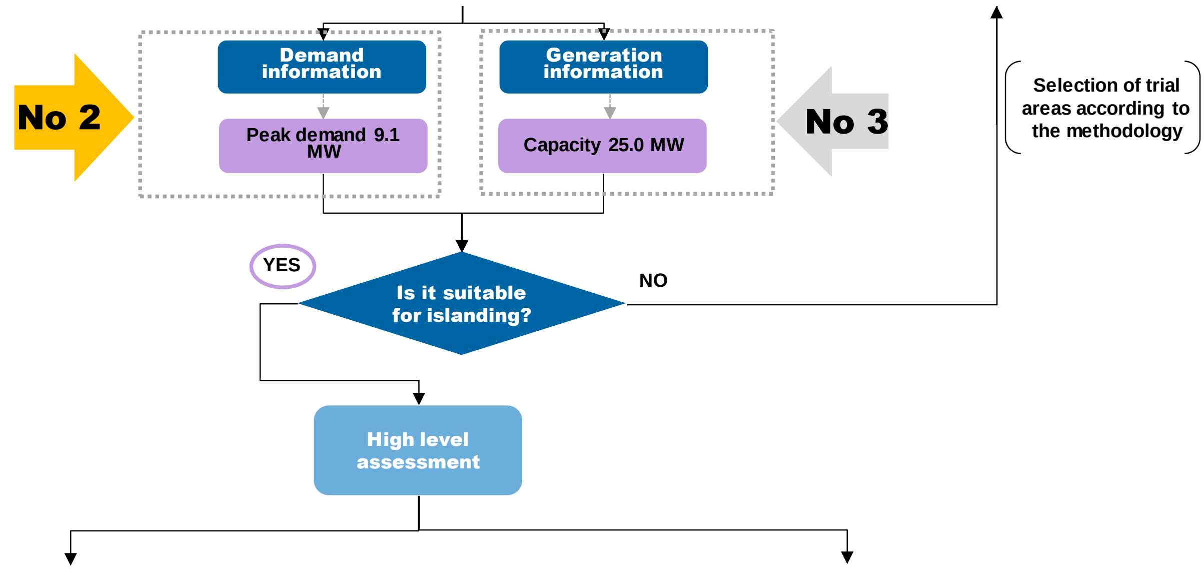



**Figure C 3: EMU/Power On diagram with highlighted proposed boundary of the islands EM1 and EM2**

## C2) Demand information




Exported measurement data has been assessed to derive demand and generation output profiles. The annual profile is as follows:

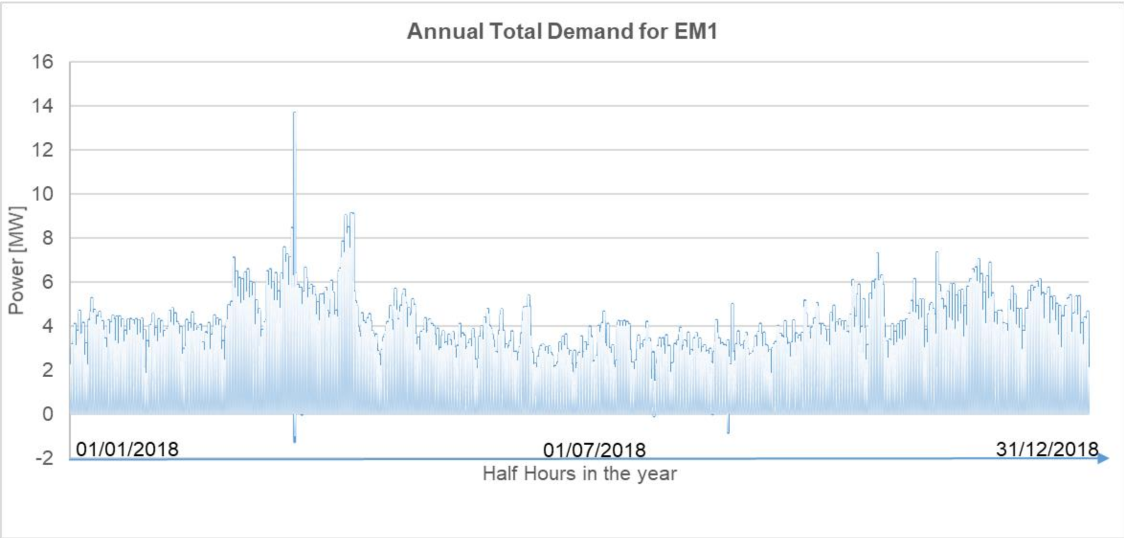



**Figure C 4: Total measured demand for EM1 (annual)**

Note: the above graph showing annual demand for EM1 reflects the negative minimum values from the measurement data. In sub-section 3.3.2 of the Feasibility Study Report, the corresponding figure for EM4 was presented for illustration. In the EM4 case, the minimum values provided from the measured data were zero. The reference to negative values is relevant to this other case.

A representative weekly profile is presented below for illustration:

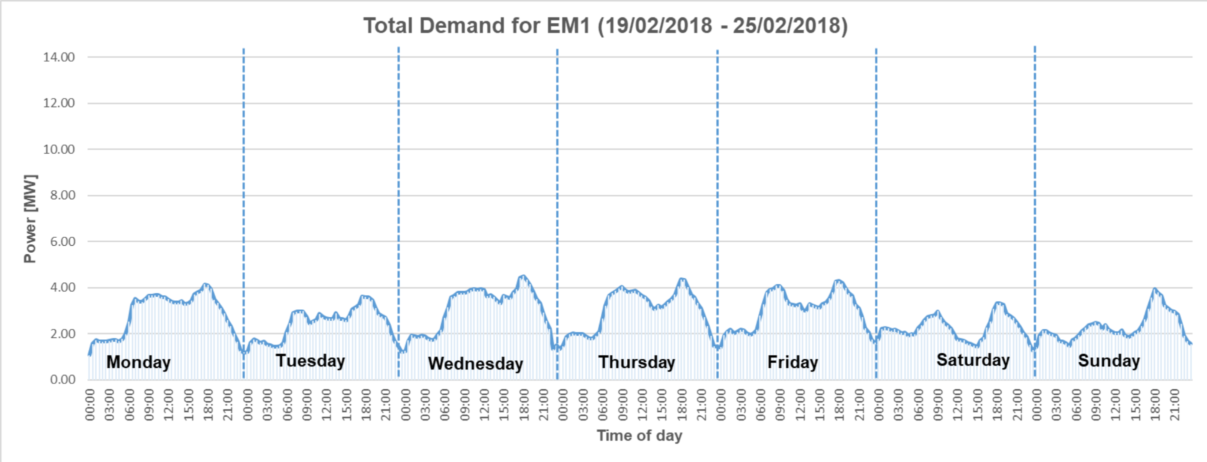



**Figure C 5: Total demand for EM1 (one-week – 19/02/2018 to 25/02/2018)**

As stated in sub-section 3.3.2 of the Feasibility Study Report, we proposed the use of the concept of Load Duration Curve (LDC) to assess the relationship between time and demand. Figure C 6 presents the annual LDC derived from the measured data for EM1 and corresponding 3-block modelling representation of the substation demand. In the form of LDCs, this shows the percentage of time the load is greater or equal to a certain level[11]. Similarly, it also shows the loads that are observed for more or less than any particular duration.

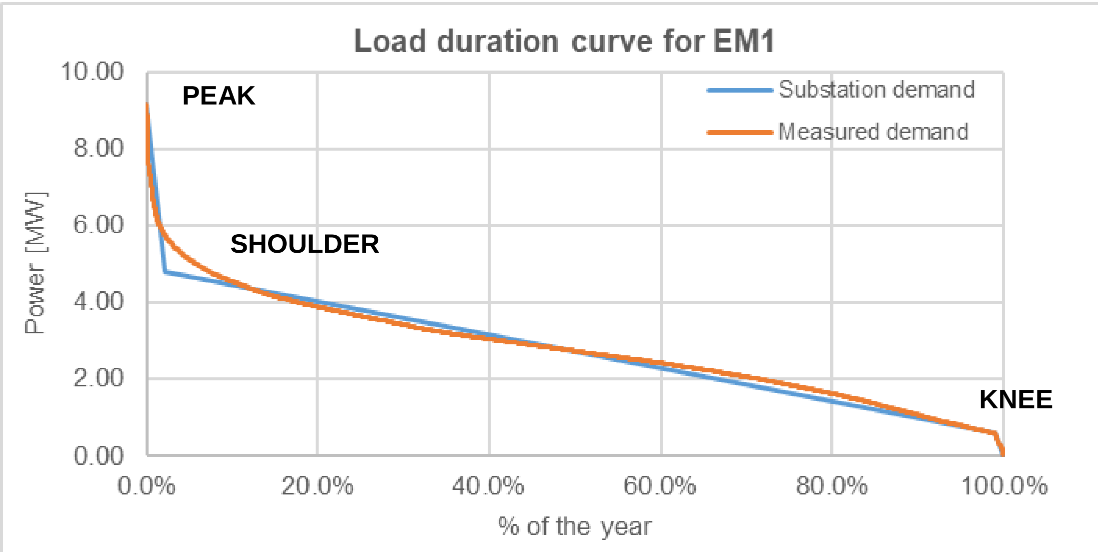



**Figure C 6: LDC derived from the measured data for EM1 and corresponding 3-block modelling representation of the substation demand**

[11] *"Load duration curve: A tool for technical-economic analysis of energy solution"* by A. Poulin, M. Dostie, M. Fournier and S. Sansreget.

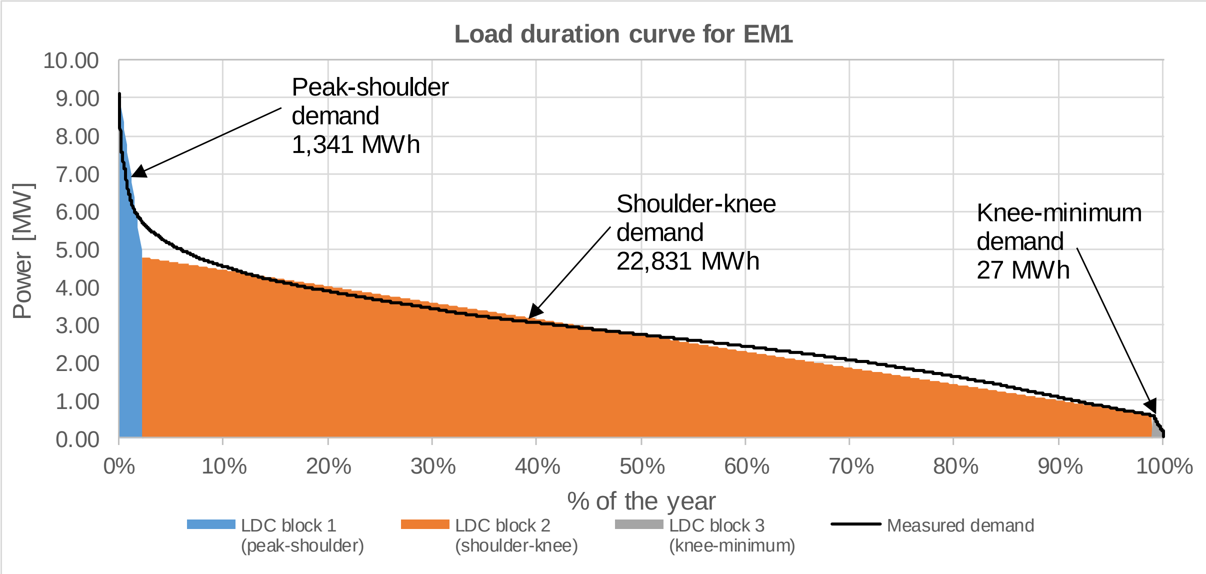
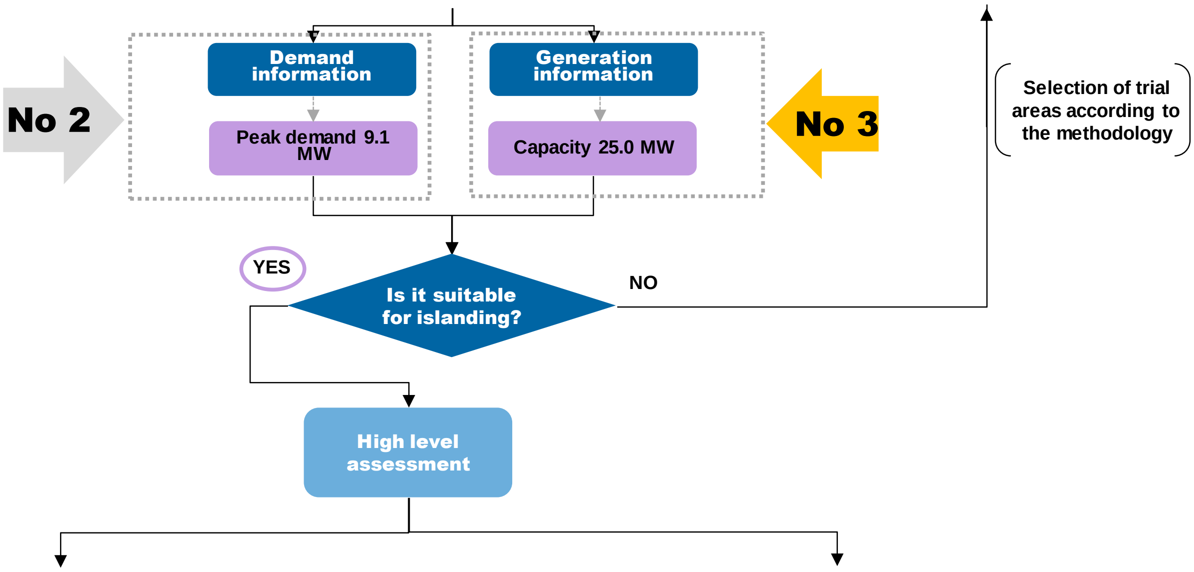



**Figure 4-1: Annual LDC for EM1**

**Table C 2: EM1 demand information**

| Description | | Unit | Value |
|---|---|---|---|
| Substation Peak time | | % | 0.0% |
| Substation Shoulder time | | % | 2.2% |
| Substation Knee time | | % | 99.0% |
| Substation Minimum time | | % | 100.0% |
| Substation Peak Demand | | MW | 9.14 |
| Substation Shoulder Demand | | MW | 4.78 |
| Substation Knee Demand | | MW | 0.60 |
| Substation Minimum Demand | | MW | 0.03 |
| Annual demand | | MWh | 24,199 |
| Load factor | | % | 30% |
| Assumed load per customer (MPAN) | | kW | 2.5 |
| Number of customers | | No. | 3,700 |
| 3-blocks | Peak-shoulder demand | MWh | 1,341 |
| | Shoulder-knee demand | MWh | 22,831 |
| | Knee-minimum demand | MWh | 27 |
| | Annual demand | MWh | **24,199** |

### C3) Generation information



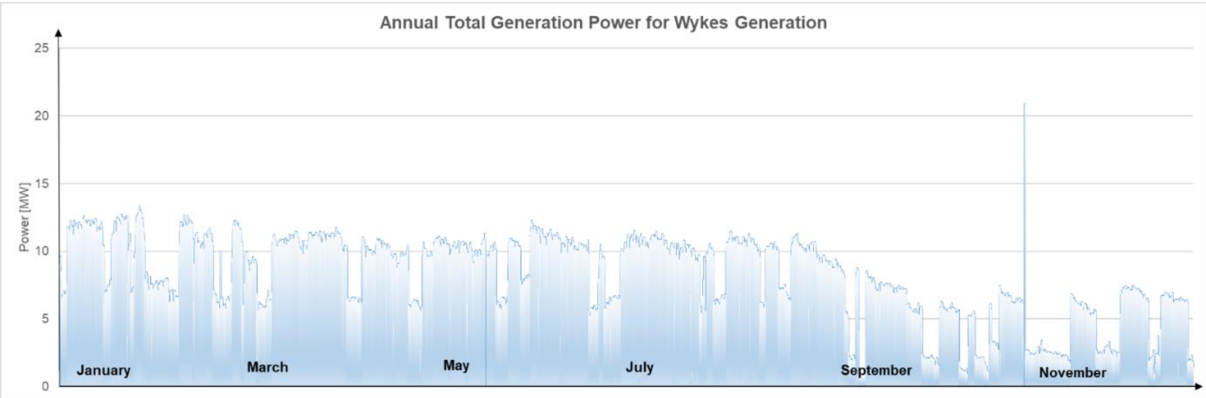




**Figure 4-2: Total measured generation for EM1 (annual)**

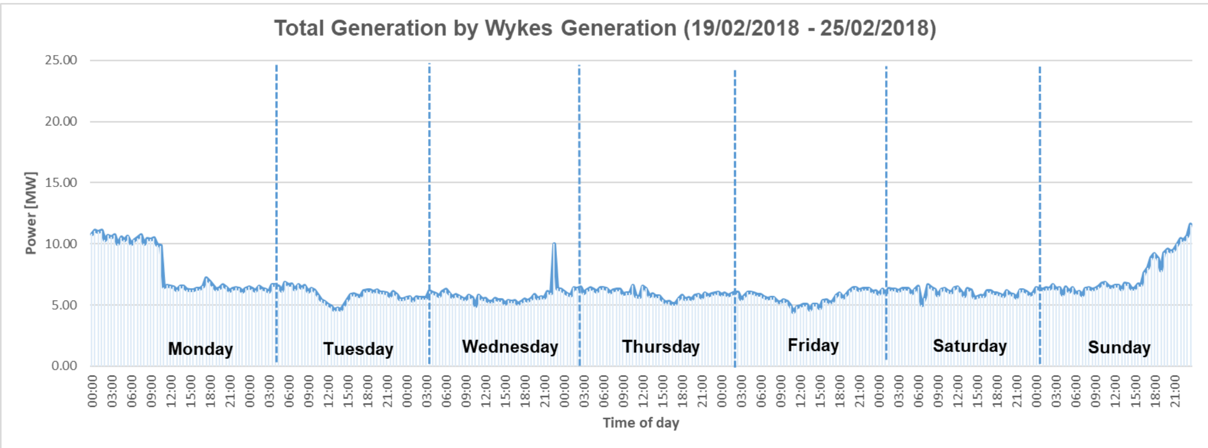
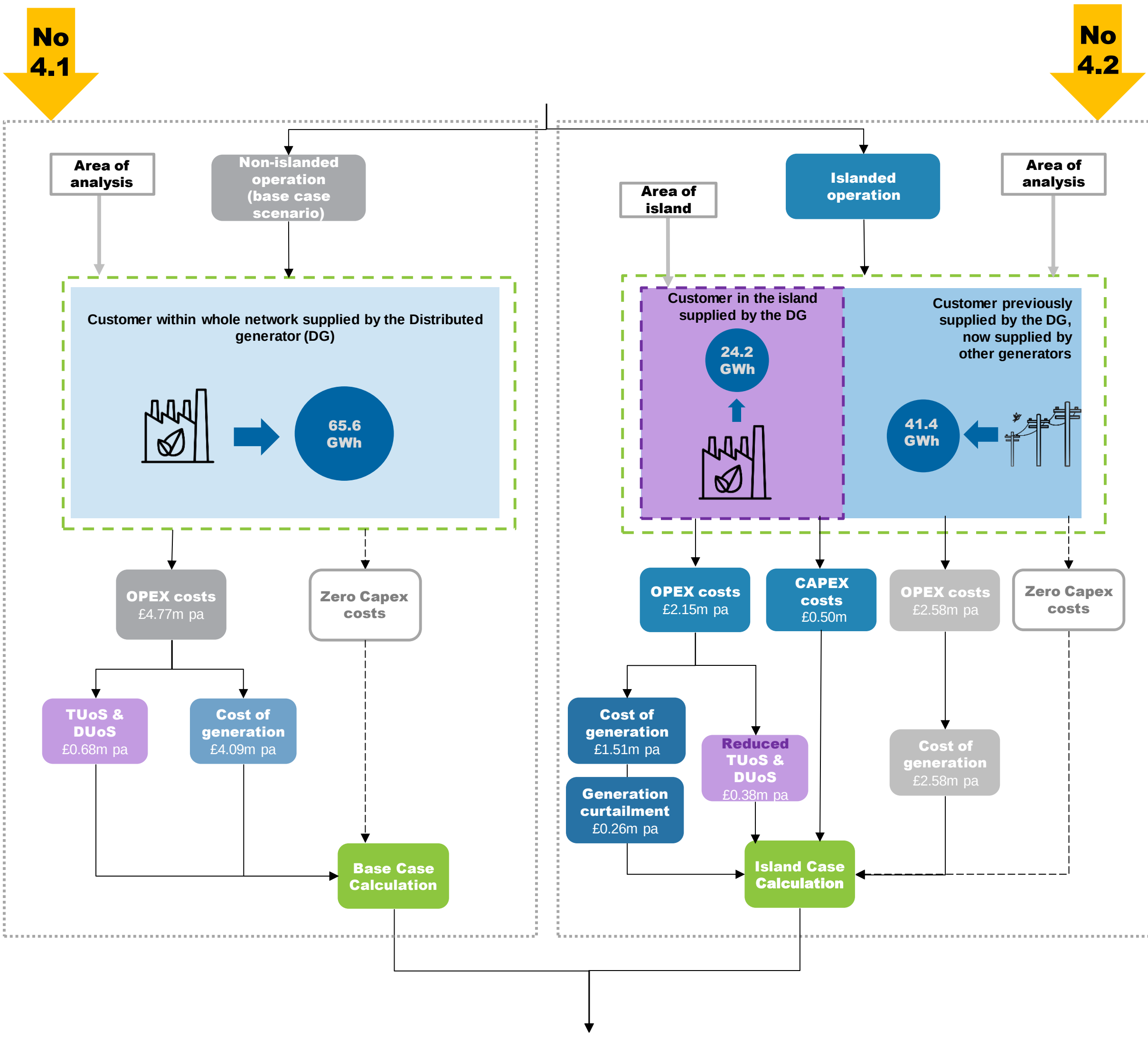



**Figure 4-3: Total measured generation for EM1 (one-week – 19/02/2018 to 25/02/2018)**

### Table C 3: EM1 generator information

| Description | Unit | Value |
|---|---|---|
| **Generation technology** | Biomass CHP | |
| **Rated capacity** | MW | 25.0 |

## C4) High-level assessment



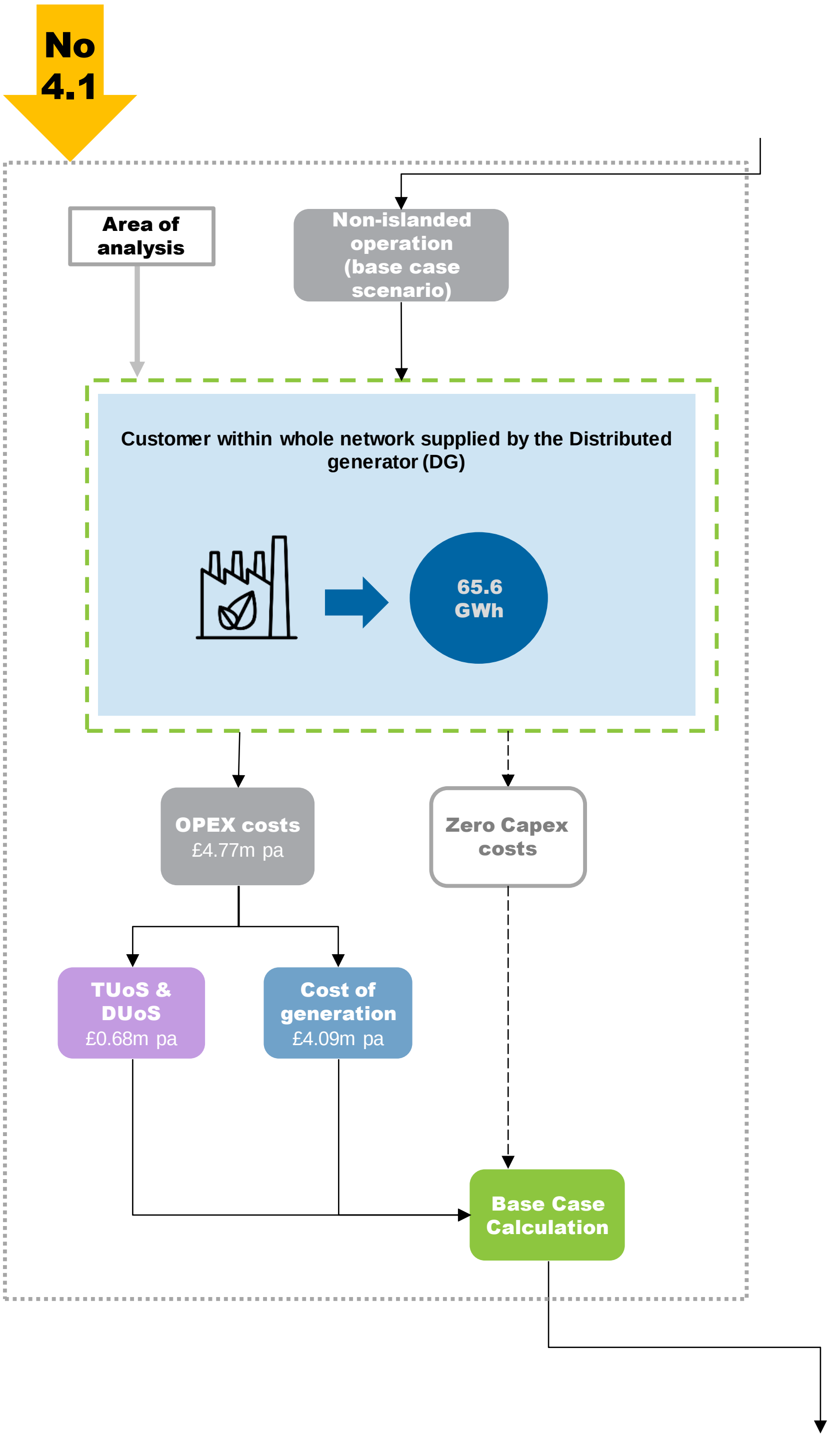
### Table C 4: Basis for wholesale generation costs

| Assumptions | Unit | Value |
|---|---|---|
| **Average annual domestic electricity bill** | £/year | £577 |
| **Average annual bill breakdown: Wholesale costs** | % | 33.5% |
| **Average annual bill breakdown: Network costs** | % | 25.5% |
| **Average annual bill breakdown: Environmental and social obligation costs** | % | 17.5% |
| **Average annual bill breakdown: Other direct costs** | % | 1.3% |
| **Average annual bill breakdown: Operating costs** | % | 17.2% |
| **Average annual bill breakdown: Supplier pre-tax margin** | % | 0.4% |
| **Average annual bill breakdown: VAT** | % | 4.8% |
| **Average annual bill breakdown: Wholesale costs** | £/year | £193 |
| **Average annual bill breakdown: Network costs** | £/year | £147 |
| **Average annual bill breakdown: Environmental and social obligation costs** | £/year | £101 |
| **Average annual bill breakdown: Other direct costs** | £/year | £7 |
| **Average annual bill breakdown: Operating costs** | £/year | £99 |
| **Average annual bill breakdown: Supplier pre-tax margin** | £/year | £2 |
| **Average annual bill breakdown: VAT** | £/year | £27 |
| **Typical domestic consumption value** | kWh/year | 3,100 |
| **Average wholesale electricity price** | £/kWh | £0.06 |

### Table C 5: Basis for DUOS and TUOS costs

| | Assumptions | Unit | Rate |
|---|---|---|---|
| **DUOS - demand customers - unit charges** | **Domestic unrestricted: Fixed charge** | p/MPAN/day | 3.350 |
| | **Domestic unrestricted: Unit charge** | p/kWh | 2.085 |
| **DUOS - site-specific EHV generator - unit charges** | **EHV generation: Export Super Red unit charge** | p/kWh | 0.000 |
| | **EHV generation: Export fixed charge** | p/day | 0.000 |
| | **EHV generation: Export capacity charge** | p/kVA/day | 0.000 |
| | **EHV generation: Export exceeded capacity charge** | p/kVA/day | 0.000 |
| **TNO network** | **TUOS** | £/customer/year | £35 |

### C4.1) Non-islanded scenario



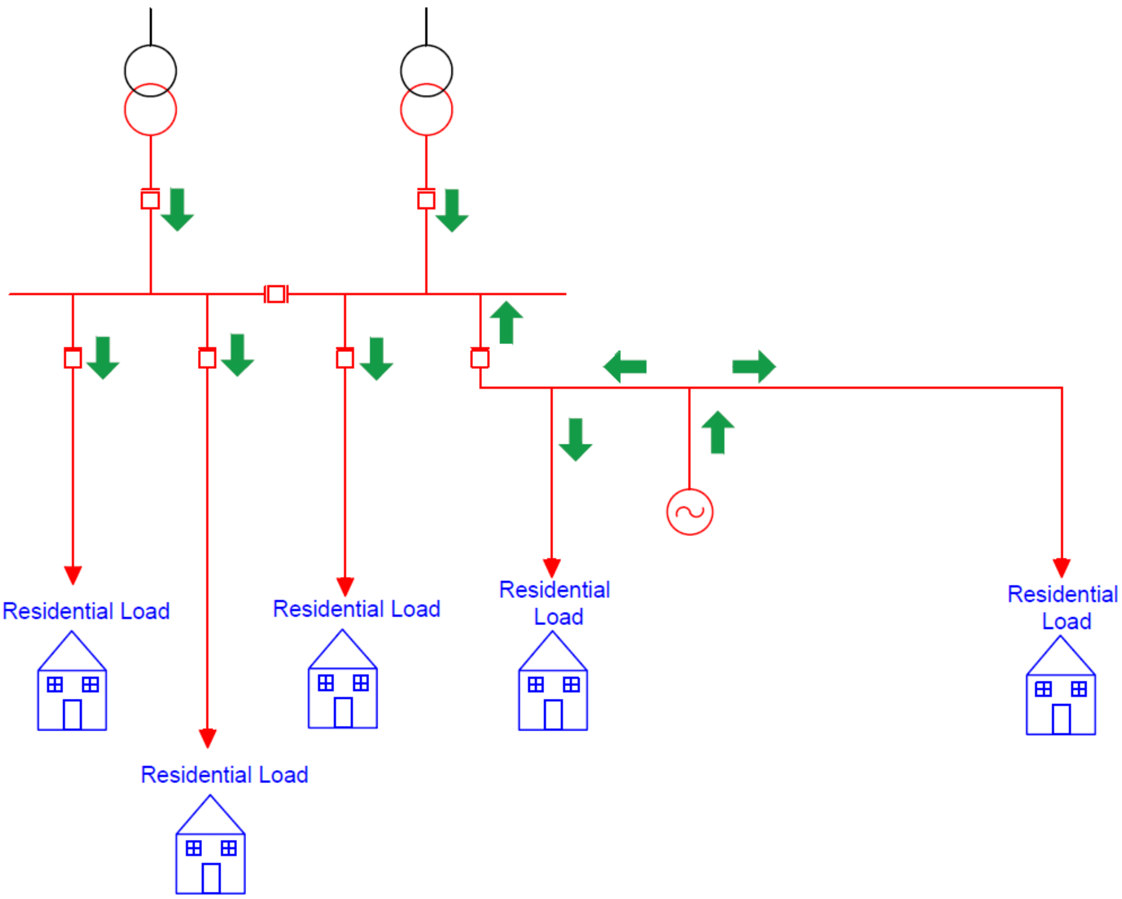



**Figure 4-4: Illustration of power flows (non-islanded scenario)**

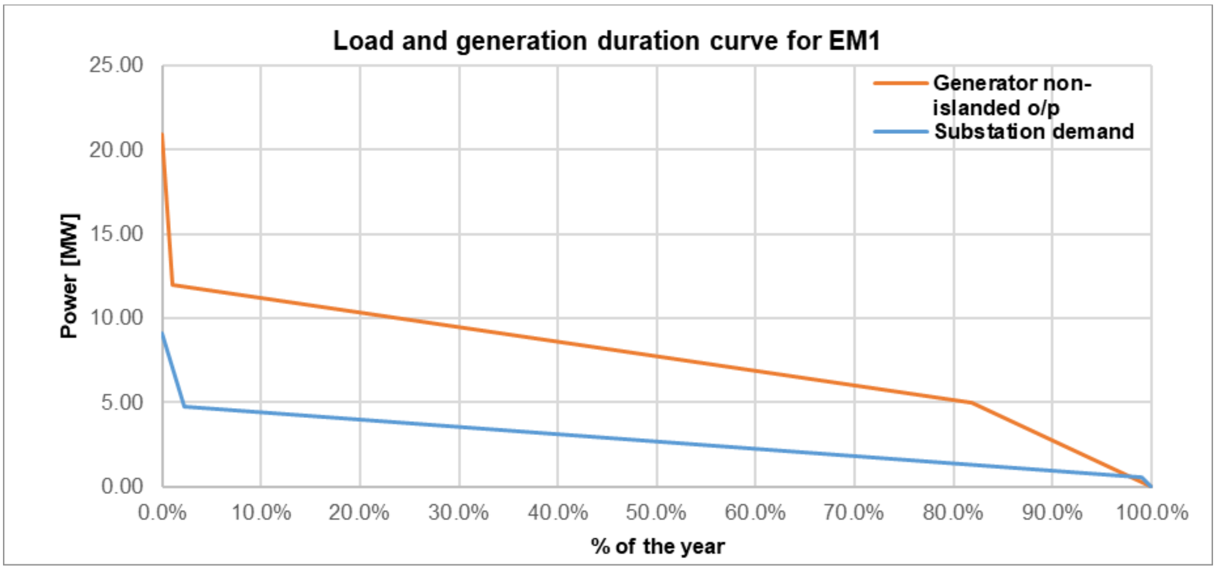



**Figure 4-5: EM1 load and generation LDCs (non-islanded scenario)**

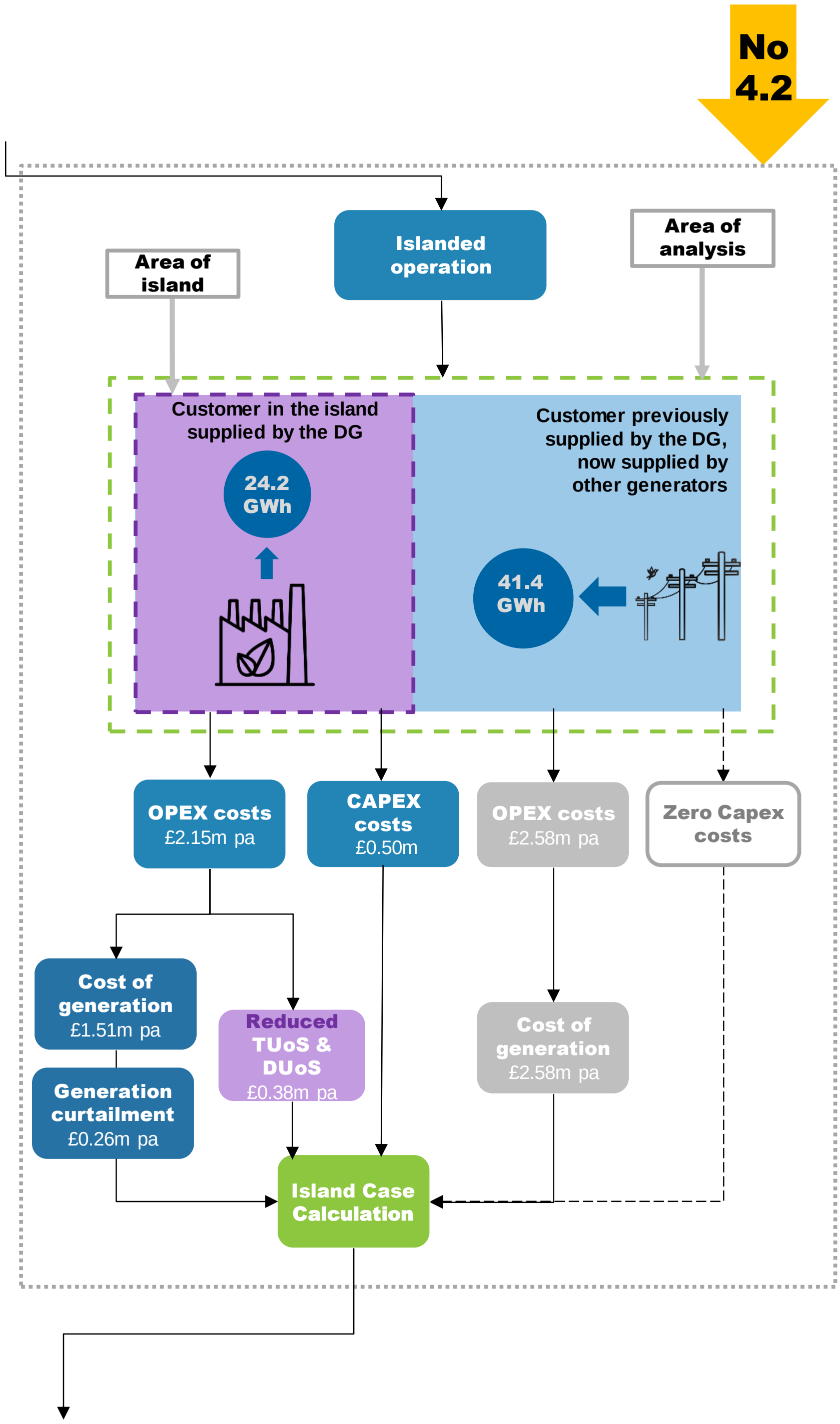
### Table C 6: EM1 generation (non-islanded)

| Description | | Unit | Value |
|---|---|---|---|
| Generator Peak time | | % | 0.0% |
| Generator Shoulder time | | % | 1.0% |
| Generator Knee time | | % | 81.8% |
| Generator Minimum time | | % | 100.0% |
| Generator Peak Output | | MW | 20.89 |
| Generator Shoulder Output | | MW | 12.00 |
| Generator Knee Output | | MW | 5.00 |
| Generator Minimum Output | | MW | 0.00 |
| Annual generator output | | MWh | 65,595 |
| Plant load factor | | % | 30.0% |
| Typical plant load factor | | % | 80% |
| 3-blocks | Peak-shoulder demand | MWh | 1,441 |
| | Shoulder-knee demand | MWh | 60,170 |
| | Knee-minimum demand | MWh | 3,984 |
| | Annual demand | MWh | 65,595 |

### Table C 7: EM1 Opex (non-islanded)

| | Description | Unit | Value |
|---|---|---|---|
| TNO network | TUOS | £/year | £129,500 |
| DNO: DUOS - demand customers | Domestic unrestricted: Fixed charge | £/year | £45,242 |
| | Domestic unrestricted: Unit charge | £/year | £504,559 |
| DNO: DUOS - generator | EHV generation: Export Super Red unit charge | £/year | £0 |
| | EHV generation: Export fixed charge | £/year | £0 |
| Wholesale generation | Wholesale generation cost of island DG | £/year | £4,092,490 |
| | Non-island OPEX Cost | £/year | £4,771,790 |

## C4.2) Islanded operation



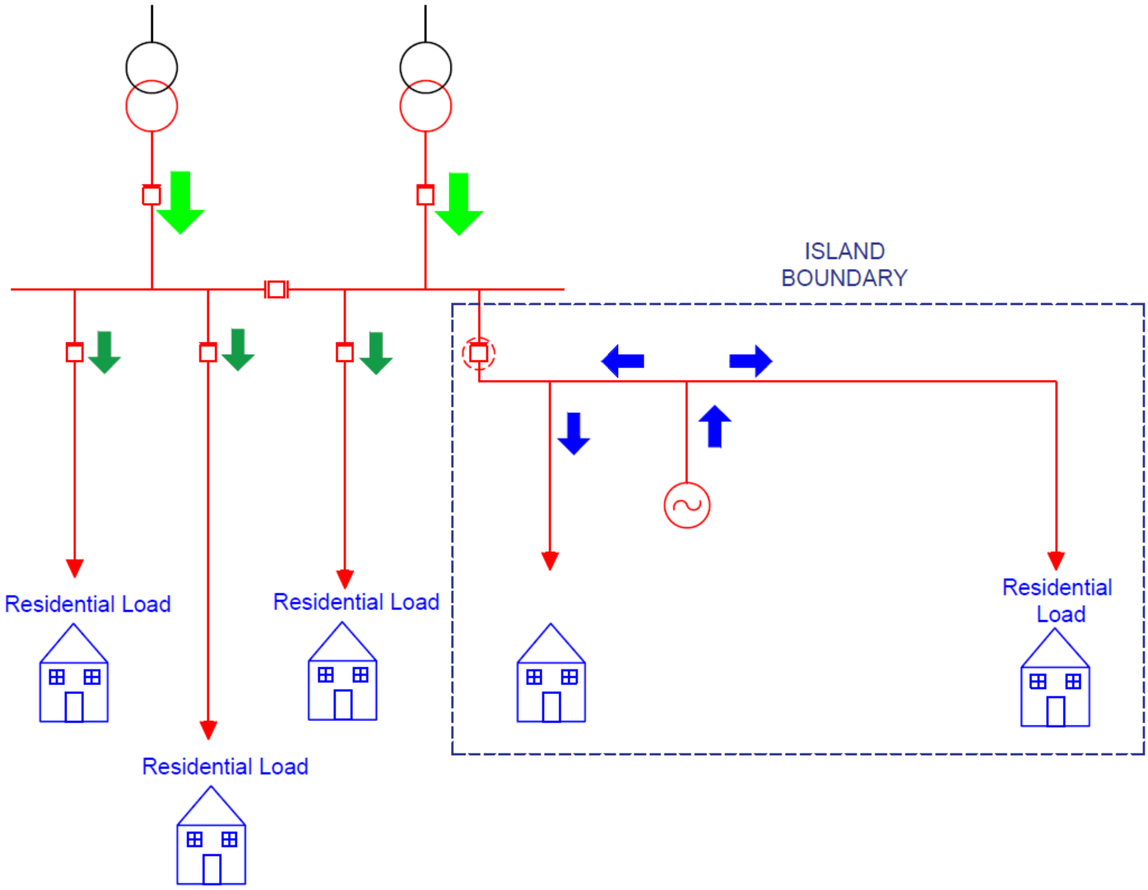



**Figure 4-6: Illustration of power flows (islanded scenario)**

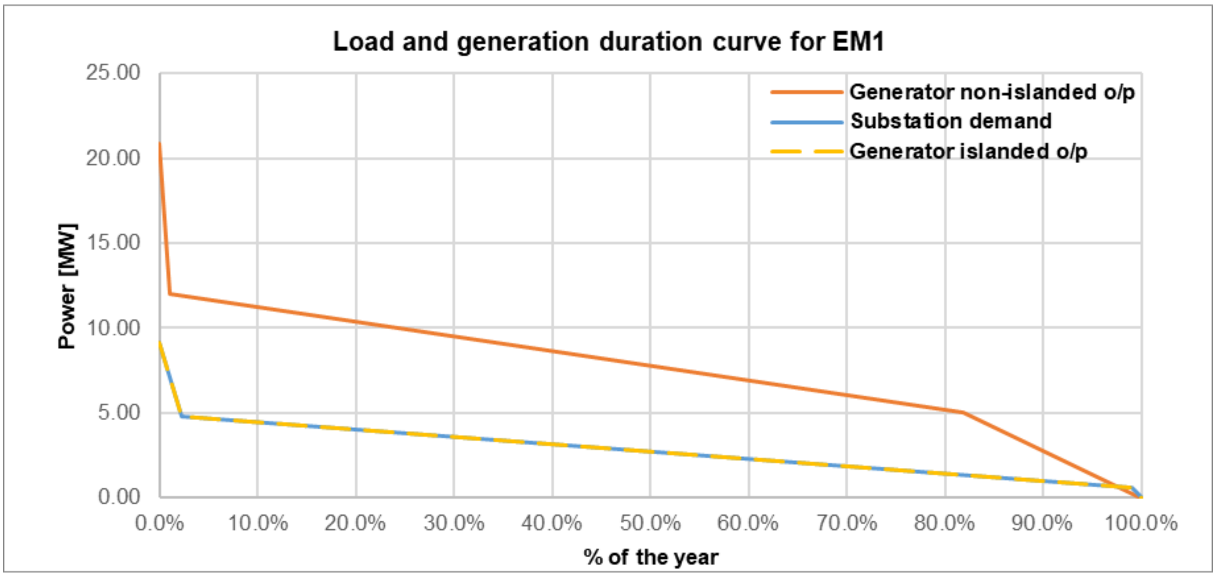



**Figure 4-7: EM1 load and generation LDCs (islanded scenario)**

### Table C 8: EM1 generation (islanded)

| Description | | Unit | Value |
|---|---|---|---|
| Islanded generator (substation) Peak time | | % | 0.0% |
| Islanded generator (substation) Shoulder time | | % | 2.2% |
| Islanded generator (substation) Knee time | | % | 99.0% |
| Islanded generator (substation) Minimum time | | % | 100.0% |
| Generator Peak Output | | MW | 9.1 |
| Generator Shoulder Output | | MW | 4.8 |
| Generator Knee Output | | MW | 0.6 |
| Generator Minimum Output | | MW | 0.0 |
| Annual generator output | | MWh | 24,199 |
| Load factor | | % | 11% |
| 3-blocks | Peak-shoulder demand | MWh | 1,341 |
| | Shoulder-knee demand | MWh | 22,831 |
| | Knee-minimum demand | MWh | 27 |
| | Annual demand | MWh | **24,199** |

### Table C 9: EM1 Capex (islanded)

| | Element | Unit | Value | Qty | Cost (£) |
|---|---|---|---|---|---|
| Generator | Generator control module | £ | £100,000 | 1 | £100,000 |
| Control and protection equipment | Synchronising panel at PCC | £ | £50,000 | 1 | £50,000 |
| | New circuit breaker | £ | £50,000 | 1 | £50,000 |
| | Replacement relay | £ | £4,000 | 64 | £128,000 |
| | Communication equipment | £ | £100,000 | 1 | £100,000 |
| | Earthing | £ | £50,000 | 1 | £50,000 |
| | Assessment of existing relays | £/day | £400 | 15 | £6,000 |
| | Study by Power System Engineer | £/day | £400 | 15 | £6,000 |
| | Design of protection system by Power System Engineer | £/day | £400 | 15 | £6,000 |
| Other | Connection charges (existing network) | £ | £0 | - | £0 |
| | Contingency percentage | % | 0% | - | £0 |
| Island Capex Cost | | | | | £496,000 |

### Table C 10: EM1 Opex assumptions (islanded)

| | Assumptions | Unit | Rate |
|---|---|---|---|
| TNO network | Factor applied to TUOS | % | 40% |
| DNO: DUOS - demand customers | Factor applied to DUOS - demand customers | % | 60% |
| | Factor applied to curtailed generation cost to account for lost revenue to DG | % | 10% |
| | Operational Life Time | years | 20 |

Table C 11: EM1 Opex (islanded)

| | Description | Unit | Value (£/year) |
|---|---|---|---|
| TNO network | TUOS | £/year | £51,800 |
| DUOS - demand customers | Domestic unrestricted: Fixed charge | £/year | £27,145 |
| | Domestic unrestricted: Unit charge | £/year | £302,735 |
| | Indicative annual TUOS reduction | | £77,700 |
| | Indicative annual DUOS (demand customers) reduction | | £219,920 |
| DNO: DUOS - generator | EHV generation: Export Super Red unit charge | £/year | £0 |
| | EHV generation: Export fixed charge | £/year | £0 |
| Islanded generator payment | Wholesale price for generation consumed in island | £/year | £1,509,815 |
| | Wholesale price for generation consumed outside island (area of analysis) | £/year | £2,582,674 |
| | Repayment of revenue for curtailed generation | £/year | £258,267 |
| | **Island OPEX Cost** | **£/year** | **£4,732,437** |

## C5) Net Present Value Comparison

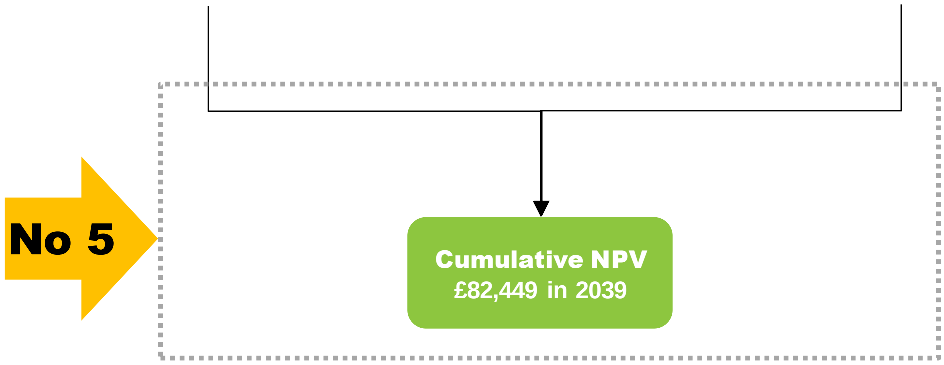



**Table C 12: EM1 excerpt from NPV calculation table**

| | Network Islanding Trial - EM1 | | |
|---|---|---|---|
| **Year** | **2019** | **2020** | **2039** |
| **Data** | | | |
| Discount rate [r] | 3.5% | 3.5% | 3.0% |
| Time period [t] | 0 | 1 | 20 |
| **Base Case Costs (B)** | | | |
| CAPEX | £0 | £0 | £0 |
| Non-island Opex | £4,771,790 | £4,771,790 | £4,771,790 |
| | | | |
| **Method Costs (M)** | | | |
| CAPEX | £496,000 | £0 | £0 |
| Island Opex | £4,771,790 | £4,732,437 | £4,732,437 |
| | | | |
| **Cost Analysis (B vs. M)** | | | |
| Undiscounted cash flow | -£496,000 | £39,353 | £39,353 |
| NPV | -£496,000 | £38,022 | £21,789 |
| NPV Cumulative | -£496,000 | -£457,978 | **£82,449** |

### Table C 13: EM1 NPV results summary for varying TUOS and DUOS factors

| Cumulative NPV in year 2039 (EM1) | | Factor applied to TUOS | | | | | |
|---|---|---|---|---|---|---|---|
| | | 0% | 20% | 40% | 60% | 80% | 100% |
| Factor applied to DUOS | 0% | 5,692,789 | 5,312,083 | 4,931,378 | 4,550,672 | 4,169,967 | 3,789,261 |
| | 20% | 4,076,479 | 3,695,774 | 3,315,068 | 2,934,363 | 2,553,657 | 2,172,952 |
| | 40% | 2,460,170 | 2,079,464 | 1,698,759 | 1,318,053 | 937,348 | 556,642 |
| | 60% | 843,860 | 463,155 | **82,449** | -298,256 | -678,962 | -1,059,667 |
| | 80% | -772,449 | -1,153,155 | -1,533,860 | -1,914,566 | -2,295,271 | -2,675,977 |
| | 100% | -2,388,759 | -2,769,464 | -3,150,170 | -3,530,875 | -3,911,581 | -4,292,286 |

### Table C 14: EM1 NPV results summary for varying DG curtailed revenue repayment and DUOS factors

| Cumulative NPV in year 2039 (EM1) | | Factor applied to wholesale cost of curtailed generation for repayment to DG | | | |
|---|---|---|---|---|---|
| | | 5% | 10% | 15% | 20% |
| Factor applied to DUOS | 0% | 6,829,521 | 4,931,378 | 3,033,235 | 1,135,091 |
| | 20% | 5,213,211 | 3,315,068 | 1,416,925 | -481,218 |
| | 40% | 3,596,902 | 1,698,759 | -199,384 | -2,097,528 |
| | 60% | 1,980,592 | **82,449** | -1,815,694 | -3,713,837 |
| | 80% | 364,283 | -1,533,860 | -3,432,003 | -5,330,147 |
| | 100% | -1,252,027 | -3,150,170 | -5,048,313 | -6,946,456 |

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