DEPARTMENT OF ELECTRONIC & ELECTRICAL ENGINEERING

University of Strathclyde Engineering

# Distributed generation on 11kV voltage constrained feeders

Report produced by University of Strathclyde for the Accelerating Renewables Connection Project


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Date of Issue: 4th September 2014

Status: Final

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# 1 Executive Summary

The connection of distributed generation at 11kV can create significant network management issues related to thermal and voltage limits. The management of thermal constraints as part of Active Network Management (ANM) schemes has been developed by a number of UK DNOs to manage constraints in the 33kV network. However, voltage management is a potentially more complex issue and one that has not been tackled by UK ANM schemes to date.

This interim report details work carried out by the University of Strathclyde to develop methods for analysis of the potential for ANM in managing voltage constraints along an 11kV feeder. The work uses Feeder 25 from St. Andrews Primary substation as a template for the methods; however the methods developed can be applied to any radial 11kV feeder.

## Existing Operating Principles

Scottish Power Energy Networks (SPEN) operates the 11kV network according to a set of standard operating principles. Distributed generation at this level is currently limited to 'Firm capacity' – the capacity which can be connected and operated on a fit-and-forget basis. The development of the ARC project will bring in the use of 'non-firm' connection agreements in which a generator will be actively managed against any network constrains to which it contributes.

The determination of whether to award a firm connection to a generator at a particular location on an 11kV feeder depends on studies into the voltage at the point-of-connection of the generator. Existing operating principles state that this should be less than 11.25kV under all standard operation conditions. The methodology for calculating the point-of-connection voltage is given in the SPEN Distributed Generation Requirements[1]. The methodology involves carrying out a detailed power flow analysis using Power Factory, and the following key points:

- Set the voltage at the primary to 11.2kV.
- Set the demand on the feeder to minimum level as detailed in SPEN's Power Factory models.
- Set the output of the proposed generator to its maximum (i.e. rated capacity).
- Run a power flow simulation to calculate the point-of-connection voltage for the generator.

Where the point-of-connection voltage exceeds 11.25kV, the generator will not be allowed to connect. The choice of 11.25kV has been developed through engineering experience from operating the network and is used to provide confidence that voltages at Low Voltage (LV) level will remain within statutory limits across the network. Voltages at both 11kV and LV levels are largely un-monitored, and secondary transformers have limited controllability. For these reasons, robust mechanisms are needed to ensure voltage levels are within required limits.

## Actively managing generation against voltage constraints

Increasing the capacity of generation connected to an 11kV feeder requires a change to existing operating principles. One option is to relax the 11.25kV limit on the point-of-connection voltage and allow this voltage to go higher. A second option is to use non-firm connection agreements to manage the voltage constraints in a similar way to the management of thermal constraints. A voltage constrained 'non-firm' generator would be allowed to connect a higher capacity than under a standard firm connection agreement but would have to curtail its output when required to ensure that the voltage does not exceed 11.25kV.

[1] Distributed Generation Connection Requirements, SPEN, ESDD-01-005, Issue No 1.

## 1.1 Modelling work to data

The Modelling work carried out is based on the Strathclyde Modelling Specification Document[2]. This document specified five Tasks aimed at developing an 11kV feeder model, assessing Business as Usual capacity for distributed generation and identifying the potential effects of adopting new operating principles. The work towards each Task is summarized below. It should be noted that the focus is on developing methodologies, and provisional results are based on data for significantly less than 1 year.

*Task 1: Set up model of single 11kV feeder based on St. Andrews data*

A model of Feeder 25 out of St. Andrews Primary Substation has been created and modified in Power Factory (See Appendix A1.1). The FlexNet project has installed a significant number of monitors on the St. Andrews 11kV and LV networks over the past year and data from this project has been made available to University of Strathclyde for the current work.

The existing Power Factory model used within SPEN has been checked against GIS based information and a number of errors in cable types and capacities were identified. These have been corrected and detailed in Appendix A1.1.

Verification against voltage measurements from the FlexNet project is currently proving difficult as the original Power Factory model does not include models of the 11kV/433V transformers. Generic assumptions about 11kV/433kV transformers have been made but the modelled and recorded voltage show significant discrepancies. It is assumed here that the 11kV section of the model is correct and this issue is discussed in more detail in the body of the report.

Data on power demands for Feeder 25 have been analysed, and half-hourly demand profiles for the months of April – June 2014 have been created. These have been used as the basis for the initial testing of the methodologies developed. A number of issues have been identified with the data.

Firstly, a significant fraction of demand is not monitored at secondary substation level. This is evident from comparing measurements of power flow out of the primary with measurements of power flow at the secondary substations. The modelling in this report adds additional demand at secondary substations to bring the total measurements in-line with the values measured at the primary.

Secondly, to verify the Power Factory model, historic measurements of demand on the feeder and voltage at the primary substation are used as inputs to the model which then simulates the LV voltages. The comparison between the simulated LV voltages and those recorded by FlexNet currently show significant inconstancies. There are currently two potential reasons for this: the use of generic 11kV/433V transformer models and the distribution of unmonitored demand (particularly for reactive power) along the feeder. UoS is continuing to work on understanding this issue.

In addition to understanding the data, a number of additions have been made to the original Power Factory model to understand the sensitivity to various assumptions. In particular, a version of the model has been created with the point at which the voltage is fixed (the infinite bus) moved from the 11kV primary busbar to the 33kV primary busbar. A load, representative of demand on other feeders from St. Andrews primary, has also been added (See Appendix A1.3).

*Task 2: Business as Usual design specification*

A methodology has been created in the form of a Power Factory script, written in DIgSILENT Programming Language (DPL) to calculate the capacity available for distributed generation at each secondary substation at each step of a time-series of demand. Illustrative results are included in this report. This method allows the

[2] See appendix 3.

drop off of DG capacity along the length of the feeder to be visualised for a particular time step, and for the DG capacity at a particular secondary substation across time to be visualised.

The method also allows the identification of estimates of 'Firm Capacity limits' at each busbar based on either the absolute minimum DG capacity at each secondary over the time-horizon investigated (April – June 2014 in this case) or the '$99^{th}$ Percentile' DG capacity at each secondary. These results have been compared with a heuristic relationship referred to here as 'the rule of 4' which suggested that the firm DG capacity will be inversely related to the distance from the primary. The comparison confirms the Rule of 4 in broad terms.

A methodology has also been developed to investigate the interaction of two DGs on the feeder (See the Power Factory model in Appendix A1.2). Studies have been run to show the effect of the location of a firm, high capacity-factor generator on the remaining network capacity over time. The location of the firm generator is shown to significantly affect the total capacity for generation on the feeder. Locating the generator at the end of the feeder leads to significantly higher constraints on non-firm generation across the feeder.

### *Task 3: Relationship between Power injection and voltage*

This task looks at the potential for two interventions to increase the capacity for DG at a particularly secondary substation.

Firstly, the effect of relaxing the constraint on the voltage at the point-of-connection of DG from 11.25kV to 11.3kV was investigated. The methodology developed under Task 2 is repeated with the relaxed constraint, and the DG capacities are compared. Results show that this can allow a significant increase in firm capacity. At the end of the feeder, approximately 200kW additional capacity can be released, in the middle section approximately 1MW. Close to the primary the effect depends on the exact method of defining 'firm capacity'. The increase in the voltage limit reduces the limiting effect of time-steps with primary voltage levels at or above 11.25kV.

The second tool investigated to increase capacity is the use of flexible demand that can allow demand to be increased to relieve curtailment. If demand and generation are on the same site this will give a 1:1 relationship with 1 unit of additional demand reliving curtailment by 1 unit. However, it is possible that the flexible demand may be located elsewhere on the feeder. A methodology has therefore been developed which identifies the increase in DG capacity created at a particular secondary substation *if demand is increased at a different secondary substation.* The methodology increases demand by 100kW at different locations on the feeder and calculates the increase in DG capacity at a particular secondary.

Results show that demand connected either at the same location as the DG or further away from the primary has approximately a 1:1 relationship with between demand and additional DG capacity. However, demand connected closer to the primary substation than DG is less effective; a unit of additional demand increases DG capacity by less than 1 unit. The effectiveness of demand decreases the closer it is to the primary.

### *Task 4: Active Management of a Single Generator on a Single Feeder*

The work in Task 2 lays the foundation for estimating the curtailment that may be experienced by a non-firm generator connecting to the feeder. The network capacity identified at each secondary substation and each time-step in Task 2 can be taken as the maximum output of a potential generator connected at that substation. The use of a historic wind resources time-series, such as the normalised output of a nearby wind farm can be used to estimate the potential generation of a DG unit connected at that substation. The two time-series can then be used to calculate the curtailment of different sizes of generator whilst ensuring network limits are maintained.

An illustration of this method has been carried out using the historic network information for St. Andrews Feeder 25 and historic output of a wind generator from the ARC region. These data are used to calculate the capacity of non-firm generation that could connect at each secondary substation whilst experiencing a curtailment of no more that 10% of available output across the time-horizon of the study.

Results suggest that the greatest potential for non-firm generation will be in the middle regions of the feeder where the potential for firm capacity is relatively low but significant additional capacity is available during most time-steps.

It should be noted that these conclusions are based on only three months of data and at least one full year of data is required before these results can be confirmed.

*Task 5: Voltage Constraints with multiple feeders*

The work detailed above has concentrated on a single feeder, with the effect of historical demand included in some studies through a single load connected to the 11kV busbar at the primary. The roll out of DG in a region is likely to lead to connections on several feeders from the same primary, and the operation of particular primaries may require modification in the light of large total capacities of DG being connected behind them.

To fully understand this work, a detailed understanding of the control systems of the primary On Load Tap Changer is required, and the potential for operating the primary as an ‘exporting primary’. As such this work has been left until the project team has reviewed the work on single-feeder modelling and Strathclyde have the opportunity to meet with SPEN technical experts to identify the OLTC transformer work.

## 1.2 Additional Conclusions and Future Work

In addition to the development of methodologies and work summarized above the modelling highlights the following *tentative* findings:

- There is significant variability in the 11kV voltage at measured at St. Andrews primary substation, ranging from approximately 10.9kV – 11.3kV. **(Task 1)**
- The voltage constrained capacity at most secondary substations modelled depends more strongly on the primary voltage than on the feeder load. **(Task 1)**
- The available firm capacity drops off exponentially as a function of distance from the primary. **(Task 2)**
- The greatest opportunity for non-firm connection agreements lies in the middle section of the feeder where firm capacity is low due to voltage constraints during a small number of time-steps, but significantly greater capacity during the majority of time steps. **(Task 4)**
- The capacity for DG on the feeder if more than one generator is connected depends on the locations of both generators and the relatively priority given to output from those generators. **(Task 3)**

The following work is required to further develop the modelling:

- The modelling of 11kv/433V transformers needs further investigation with input from SPEN on this aspect of the Power Factory model.
- There are significant inconsistencies between power flow measurements at St. Andrews Primary and the secondary substations. This is assumed to be because not all the secondary substations are monitored. We suggest a meeting with the FlexNet team to discuss this aspect of the project.
- The effect on primary voltages of the changes to power injected to the feeder by Distributed Generation needs further analysis. This is required to verify conclusions made in **Tasks 3 and 4,** and should be agreed before significant progress can be made on **Task 5.**

# 2 Task 1: Set up model of single 11kV feeder based on St. Andrews data

The aim of Task 1 is to set up a usable model of an 11kV feeder to develop methodologies for analysis of the connection of Distributed Generation (DG) and provide insight into the potential for operating a voltage constrained feeder as part of the ARC project. SPEN have provided a Power Factory model of Feeder 25, an 11kV feeder from St. Andrews Primary substation. The FlexNet Project has carried out detailed monitoring of this section of the network, and analysis of the data collected forms an important part of the work within this task.

A Power Factory model of St. Andrews Feeder 25 has been provided by SPEN. The components of this model have been checked against GIS based data held by SPEN. Several errors were identified in the original model of the including incorrect cable types (for example copper instead of aluminium) and incorrect cable lengths. A full list of the errors identified is given in Appendix 1.1.

The initial model also includes a number of distributed generation studies carried out by SPEN dated between September 2013 and April 2014. These studies have been removed for the purposes of this work. Figure 1 shows an overview of the feeder as modelled in Power Factory. More detailed information on the Power Factory models used is included in Appendix 1.

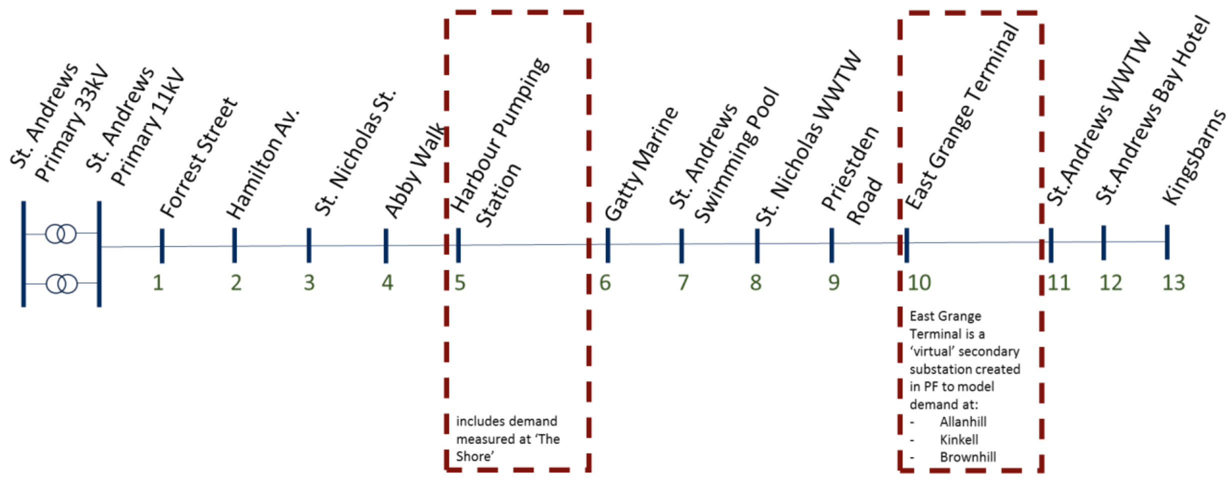



*Figure 1: Overview of the Power Factory model of Feeder 25*

The original Power Factory model does not include 11kV/433V transformers and load is connected directly to the 11kV bus-bar at the secondary substation. The model used for this work has been extended to include 11kV to 433V transformers with impedances in line with the standard values used by SPEN. However, it should be noted that the modelling of 11kV/433V transformers has not been verified, and significant inconsistencies exist between historic measurements and Power Factory modelling results for LV voltages.

In addition to the base model, which begins at the 11kV busbar at St. Andrews Primary, a derivate model has been created which includes 2 generic 33/11 kV transformers, the 33kV busbar and an additional load representing demand on other feeders(See Appendix A1.3). This allows the effect of varying voltage drops through the primary transformers to be modelled when varying the capacity of distributed generation and load on the primary substation.

## 2.1 FlexNet Data Overview

Modelling of the St. Andrews 11kV feeder makes use of data recorded as part of the FlexNet project. This data consists of measurements made at the 11kV busbar at the primary substation and at the LV side of secondary transformers along the feeder. Two monitor types are used – Subnet and GridKey.

At each secondary substation the following data useful to this project is recorded on each phase:

- Real Power (P)
- Reactive Power (Q)
- Apparent Power (S)
- Current (I)
- Power Factor (pf)
- Voltage (V)

At substations fitted with Subnet equipment values for V, I and pf are recorded to a greater number of significant figures than P and Q which are often given to only 1 or 2 significant figures. As such all values of P and Q used in these studies are derived from V, I and pf. Data is recorded at either 1 or 10 minute resolution. This analysis reduced the data to half-hourly resolution.

Measurements at St. Andrews Primary include Line-to-Line voltages between phases A and B and phases B and C (there is no recording of Voltage between Phase C and A). There are also measurements of P, Q made with a two-power meter. Phase-by-Phase powers are not recorded but the total of the two measurements of P and the two measurements of Q give the three phase values.

### 2.1.1 FlexNet Data – Uncertainties

There are number of complications with the FlexNet data which affect the Power Factory model.

*Inconsistency between Primary and Secondary measurements*

Firstly, there is a significant inconsistency between power flow measurements at St. Andrews Primary and those recorded at the secondary substations. A comparison has been run which assesses the total real and reactive power measured at secondary substations with the total measured at the primary. If the secondary measurements account for all the demand on the feeder, the sum of secondary measurements will approximately equal the power drawn from the primary with any small differences due to electrical losses on the feeder.

However, the secondary measurements do not account for all the demand. Summing primary power measured across all phases and similarly aggregating all secondary measurements across all secondary substations and all phases suggests that the secondary measurements account for approximately 50% of total real power and 25% of total reactive power demand. The two time-series for primary and total secondary real Power are shown in Figure 2. The primary measurement varies from 1.6 – 3.4 times the total secondary powers at those times with an average of 2.2.

FlexNet measurements of the current at St. Andrews primary have been verified against PI records for the same period and show close agreement as shown in Figure 3. As noted above, the current, voltage and power factor readings have been used to calculate P and Q at the primary and it is these values of P and Q which have been compared against secondary values calculated in a similar way.

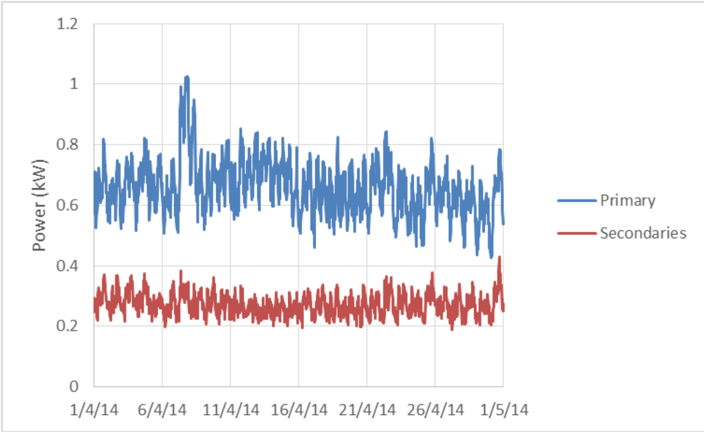



*Figure 2: Comparing primary and secondary power measurements for Feeder 25, April 2014*

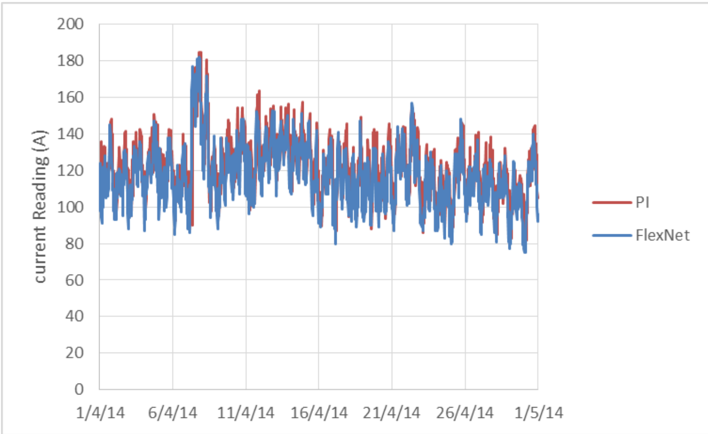



*Figure 3: Comparison of FlexNet and Pi records of current flow on Feeder 25, April 2014*

The most likely reason for the inconsistency between primary and secondary measurements power records is that some secondary substations are unmonitored. In particular, the rural region of the feeder has a number of unmonitored secondary substations. The magnitude of the difference between primary and secondary measurements with respect to reactive powers is surprising even given the number of unmonitored secondary substations.

To account for the inconsistencies we have assumed that the measurements of real power from the primary are accurate and electrical losses are negligible compared with the inconsistencies in the data. To correct the secondary power measurements two techniques have been used:

- The value of P and Q at each secondary substation is scaled up so that the aggregate real power across the feeder is equal to the real power drawn from the primary. This spreads the missing demand across the whole feeder. Demand profiles calculated using this method are referred to as scaled profiles.
- Additional load is added in the rural section of the feeder. Specifically: ¼ of the missing load is added at each of: East Grange Terminal Pole, St Andrews Bay WWTW, St. Andrews Bay Hotel and Kingsbarns. The missing demand is equally spread across the three phases. This method assumes that the missing demand is fully located in the rural region of the feeder. Demand profiles from this method are referred to as extra rural demand profiles.

Throughout this report, unless otherwise stated, the second of these two methods is used to model demand on the feeder.

The real and reactive power as measured by the secondary substations are both scaled by the same value based on missing real power.

At this stage UoS suggested that, to agree on the most appropriate correction method for real and reactive power, and to further understand the very large difference in reactive power measurements, we suggest meeting with the FlexNet technical team.

*Inconsistency between recorded and modelled LV voltage measurements*

As noted above, the Power Factory model provided by SPEN only included the 11kV section of the network. Both the 33kV and LV connections are omitted. UoS have added generic 11kV/433V transformers and transferred the monitored loads to the LV side of the secondary substations. The objective of this is to allow simulation of the LV voltage levels for direct comparison with the FlexNet Monitoring.

Simulation of the LV voltage involves setting the primary 11kV voltage to the historically recorded value, setting the LV loads to the historically recorded values of P and Q, running a load flow and recording the LV voltages. A script has been created to automate this process for all half-hour time steps during April – June 2014 (see Appendix A2.1 for details).

Results for a particular time-step with intermediate demand are shown in Figure 4. The grey lines show the values recorded by FlexNet and the coloured lines show the results simulated with Power Factory. The red line uses the recorded values of P and Q at the secondary substations and as discussed above misses a significant amount of demand as monitored by Primary. The blue lines use the scaled demand profile and the green lines use the extra rural demand profiles. In all cases, simulated voltages are significantly higher than the measured values at the majority of secondary substations.

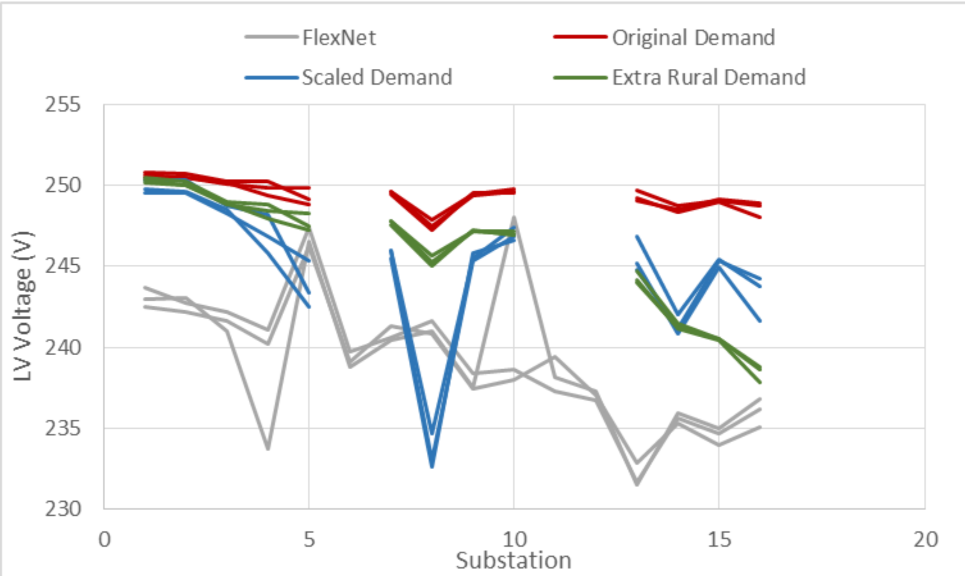



*Figure 4: LV voltages measured by FlexNet and Simulated on Power Factory. Simulation results include three demand distributions representing the demand recorded by FlexNet secondary substation monitors and the addition of additional demand to match measurements at the primary.*

Two potential reasons for the inconsistency are the 11kV/433V transformer models and measurements of reactive power demand. The components forming the 11kV cables and overhead lines have been carefully checked against SPEN's GIS based database of equipment and are assumed to be accurate.

The secondary transformer models currently used are taken from the 'Library Distribution Design Manual' provided with the Power Factory model with impedances checked against the standard values for particularly sizes of transformer.

Given the significant differences between primary and secondary measurements of reactive power demand there is the potential that the reactive powers used in the model are not correct. Reactive power drawn through the 11kV/433V transformers can significantly affect the LV voltage levels. As such confirmation that the reactive power measurements from FlexNet are accurate is important in verifying this model.

Despite the need to further verify the modelling of LV modelling, much of the analysis required by the ARC project focuses on the 11kV level. As it is likely that the LV voltage errors are related to the 11kV/433V transformers, UoS is continuing with the current model which requires only 11kV voltages. This allows the development of methodologies and outline results. Simulation results for the 11kV voltage profiles for single time-steps are shown in Figure 5 for the three distributions of demand. It is clear that verifying the quantity of real power demand and its distribution along the feeder is important for identifying the voltage constrained DG capacity towards the end of the feeder.

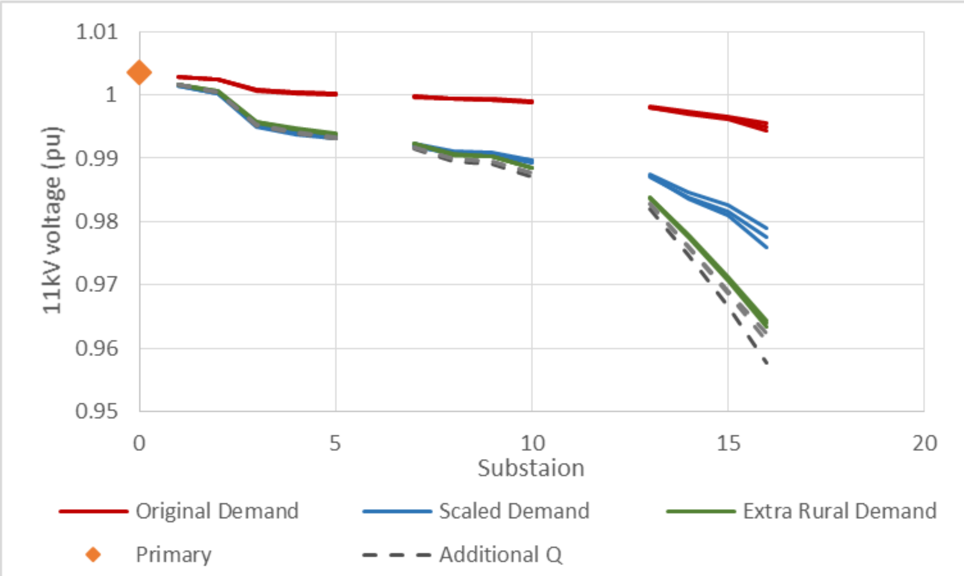



*Figure 5: 11kV voltages in Per Unit values for a single times step with three distributions of demand.*

An additional simulation carried out for sensitivity is to double the additional Q included in the extra rural demand profile. This is shown by the dashed lines in Figure 5 and represents the case where P is increased by 2.66 compared with the total monitored secondary demand, and Q is increased by 5.32. The significant additional Q, connected at the end of the feeder makes only a relatively small difference to the 11kV voltage (it should be noted that this makes a more significant difference to the simulated LV voltage).

# 3 Task 2: Business-as-usual design specifications: static

The existing design principles for the operation of an 11kV feeder with distributed generation can been described by the following rules:

- The On Load Tap Changers (OLTC) at the primary operate to maintain the voltage be close to 11.2kV. The SPEN Design Manual suggests using 11.2kV as the primary voltage for distributed generation studies if actual readings are not available[3].
- The limit on DG connecting to a feeder such that "Typically, 11kV connections will be constrained to an upper limit of 11.25kV at the Point of Common Coupling (POCC)"[4]

In addition, the following limits on the allowed voltage levels are identified:

- The 11kV network should be operated in the region 11kV + / - 6% corresponding to 10.34kV – 11.66kV.
- The LV network should be operated in the region 230V +10% - 6% corresponding to 216.2V – 253V.

One objective of studying the FlexNet data is to identify if these rules are obeyed in practice.

### 3.1.1 Voltage at the Primary Substation

In reality the voltages recorded at the primary vary significantly from 11.2kV. Phase to Phase voltages are recorded between phases A-B and B-C, there is no recording of voltage between Phases C-A. The minimum voltage recorded at the primary during the period April- June 2014 is 10.903kV and the maximum is 11.338kV. The voltage between phases A-B is in general higher than voltage between phases B-C. The distribution of voltage is shown below in Figure 6. With the exception of one outlier, the voltage imbalance is always less than 1%, with the two greatest imbalances between $V_{a\text{-}b}$ and $V_{b\text{-}c}$ measured as 153V and 112V with $V_{a\text{-}b}$ higher on all but one occasion (Figure 7).

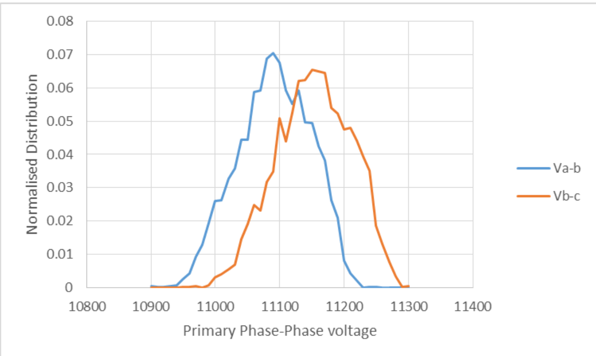



*Figure 6: distribution of phase-to-phase voltages at St. Andrews Primary during April 2014*

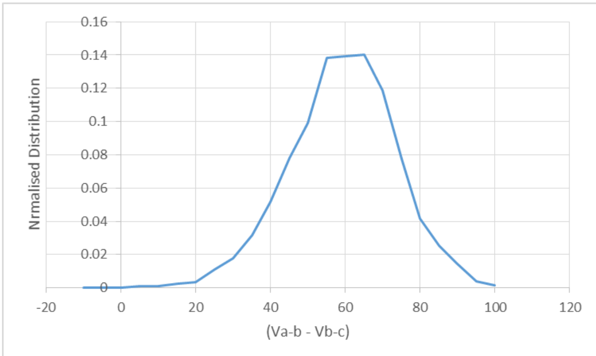



*Figure 7: Voltage imbalance at St. Andrews Primary during April 2014*

[3] Distributed Generation Connection Requirements, SPEN, ESDD-01-005, Issue No 1.
[4] Distributed Generation Connection Requirements, SPEN, ESDD-01-005, Issue No 1.

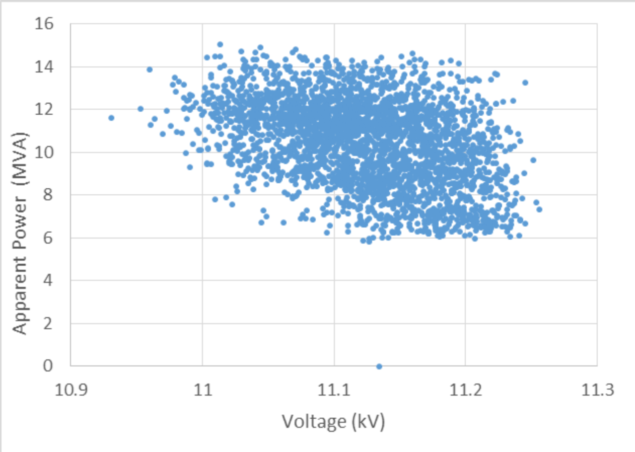



*Figure 8: No correlation is seen between Primary voltage and demand on the feeder, nor between Primary voltage and total Primary demand.*

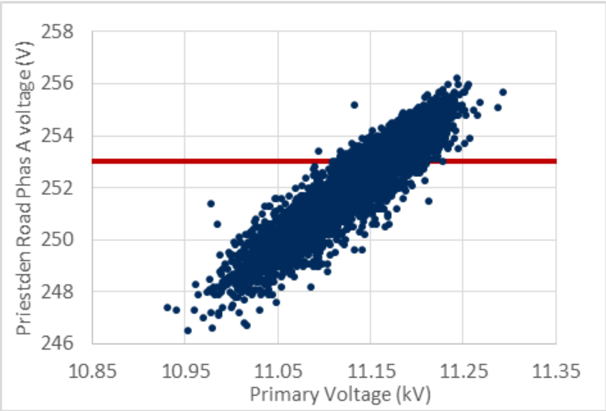
The recorded data shows that the primary voltage is operating below 11.2kV for the majority of the time. The voltage $V_{a\text{-}b}$ is less than 11.2kV for 99% of time-steps and voltage $V_{b\text{-}c}$ is less than 11.2kV for 75% of the time. The average of the voltage is 11.09kV and 11.16kV for $V_{a\text{-}b}$ and $V_{b\text{-}c}$ respectively.

The value of $V_{b\text{-}c}$ is also higher than 11.25kV during 186 time-steps meaning that during these periods there would be no capacity for distributed generation close to the primary substation due to the voltage limit of 11.25kV at the point-of-connection of distributed generation.

### 3.1.2 LV measurements at secondary substations

Measurements of the LV system voltage show that voltages in excess of 253V were recorded on 1323 occasions out of a total of 209,712 measurements. Of these, 178 occurred at Harbour Pumping Station and 1159 occurred on 'Phase A' at Priestden Road. This phase of Priestden Road is therefore overvoltage for 27% of the time. No under-voltage LV readings were recorded.

The LV voltages recorded at the primary substations are well correlated with the primary voltage, for example for Priestden Road, Phase A, the correlation between LV reading and average Primary voltage is shown in Figure 9 (a). The LV voltages are also correlated with total feeder demand, and Figure 9 (b) shows this for Priestden Road Phase A. The conclusion is that, as expected, overvoltage at Priestden Road will occur when primary voltage is high and total feeder demand is low. The data shows only low correlation between voltages and demand at Priestden Road itself, any local effect being swamped by primary voltage and overall feeder demand.



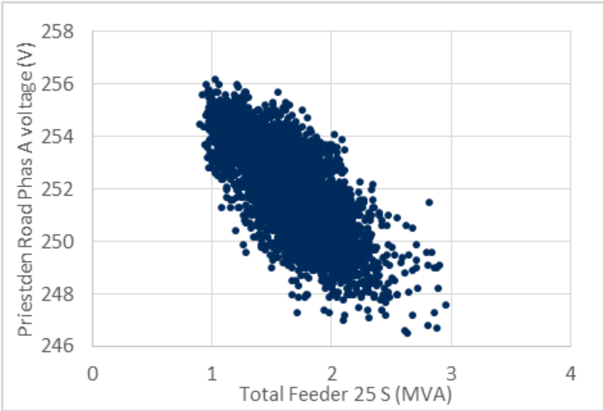




*Figure 9: Correlation between (a) primary voltage and LV voltage at Priestden Road on phase A, and (b) total Feeder demand and LV voltage at Priestden Road phase A.*

### 3.1.3 Modelling Feeder Voltage levels

The process of modelling historic LV voltage readings and the comparison with recorded values is discussed in Section 2.1.1 above. However, for the studied detailed in this report the 11kV rather than LV voltage profile is required. A script and methodology to simulate the voltage profiles along the feeder is given in Appendix A2.1. The methodology records the simulated values of both the LV and 11kV voltages at each secondary substation and the values of the 11kV voltages are used in further studies.

Simulations have been carried out to model the 11kV voltage profile along the feeder for each time-step during April-June 2014. The modelling has used the adjusted extra rural demand profiles. Figure 10 Shows two typical voltage profiles, where the horizontal axis represents distance along the feeder. The primary voltage (shown at zero distance) is the average recorded voltage across the two measured phases at the primary. Two time steps are show: the high demand time step shows the greatest voltage drop along the feeder.

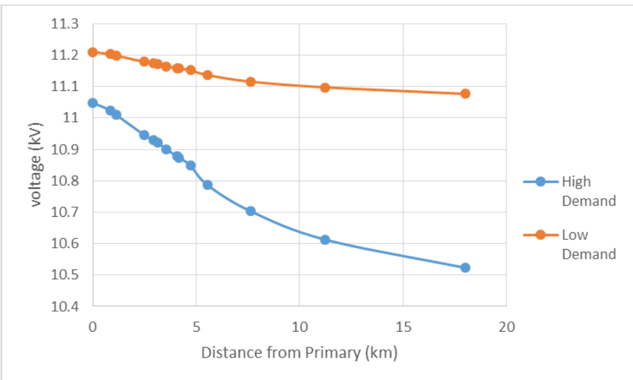



*Figure 10: Example 11kV voltage profiles simulated by Power Factory representing high and low demand time-steps*

Figure 11 shows the distribution of voltages at each secondary throughout April – June as modelled by Power Factory. The dashed central line shows the median value of voltage at each substation. To either side of this are lines representing confidence bounds, for example the light grey lines shows the range within which voltage at that location is in for 99% of the time – the 99th percentile limit. The red and blue lines show the absolute maximum and minimum values modelled at each time-step.

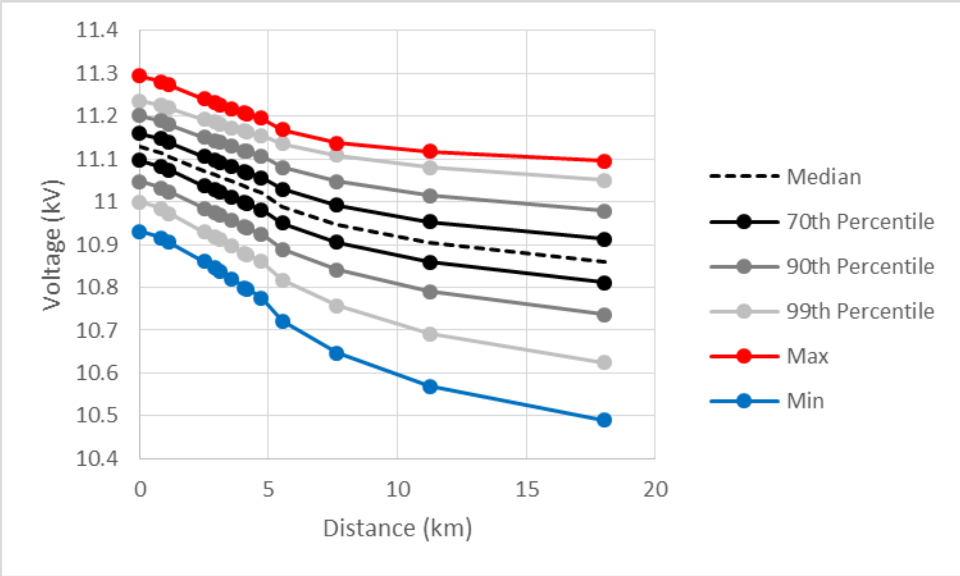



*Figure 11: Statistical properties of voltage variation along the feeder. The central line represents the median value of voltage at each substation while moving progressively away from the centre shows higher percentile values. The bounding lines, top and bottom represent the absolute maximum and minimum values simulated at each substation.*

The results suggest that the voltage on the 11kV network is operating within bounds for the 11kV system.

## 3.2 Generation capacity on Feeder 25 under existing operational rules

Distributed generation connected to an 11kV feeder under existing rules for management of the network must meet two constraints.

- At periods of low demand a distributed generator must not be capable of overloading the thermal limits of the feeder.
- Under all standard operating conditions, from minimum to maximum demand, voltage limits across the feeder must be maintained.

The second of these is currently met by limiting the voltage at the point-of-connection to a maximum of 11.25kV. Both of these constraints are traditionally met by only setting a Firm Capacity limit; the use of non-firm contracts however allows greater capacities to connect on condition that they respond to curtailment signals and reduce their demand when required to maintain the two conditions.

To investigate the capacity available for distributed generation at each of the secondary substations Power Factory studies have been run for each half hour in April 2014. For each time-step the maximum capacity that maintains the thermal and voltage limits is calculated at each secondary substation *under the assumption that there is only one distributed generator connecting.*

To carry out this study a Power Factory script has been developed which loads the historic conditions for a particular time-step and then finds the maximum capacity of distributed generation that maintains the thermal and voltage limits for that time step. The result is a time-series of capacity limits for each secondary substation. More detail on the methodology and script developed are given in Appendix A2.1.

The methodology developed is applied to the period April – June 2014 using the adjusted demand profile with addition demand in the rural section. Figure 12 shows three examples of the available DG capacity along the length of the feeder. In all three cases the capacity at the first two secondary substations (Forrest St. and Hamilton Ave.) are constrained by the thermal limit on export form the feeder. The limiting power flow along the feeder is approximately 4.3MVA, and the maximum thermally constrained DG capacity is therefore approximately 4.3MW plus current demand on the feeder.

For the cases of low demand, DG at all substations from 3 - 13 are voltage constrained with the limit of 11.25kV at the point-of-connection reached before the thermal limit of the feeder. With high demand, substation 3 is thermally constrained and 4 – 13 are voltage constrained. However, with the intermediate demand level, substations 1-10 are thermally constrained and the voltage constraint is only binding between substations 11 and 13.

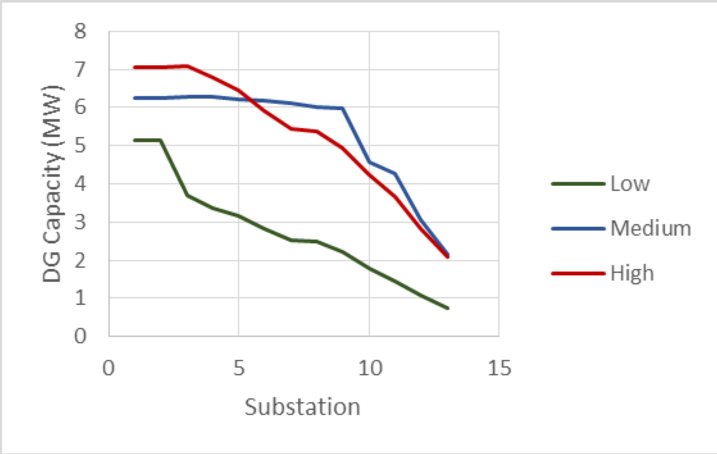



*Figure 12: Capacity profile along feeder for three demand scenarios during April – June 2014.*

The lack of voltage constraints in the central section of the feeder for the intermediate demand case is due to a low primary voltage. The primary voltage for this time step is 10.97kV compared with 11.17kV for the low demand case and 11.13kV for high demand. The low primary voltage creates significant voltage headroom even out to several km along the feeder. This shows the importance of primary voltage on the available capacity for DG on the feeder.

Figure 13 shows the distribution of available capacity at several secondary substations in the form of a 'capacity availability curve'. This shows the fraction of time that the available capacity is greater than a given quantity and can be interpreted as the fraction of time the network can accept full output from a given capacity of generation at that location. Capacity availability curves move towards the left for substations further along the feeder showing the reduction in available capacity. Where the capacity availability curve is close to 1, the network can almost always accept that capacity of generation. Where it is close to zero the network can almost never accept that capacity of generation.

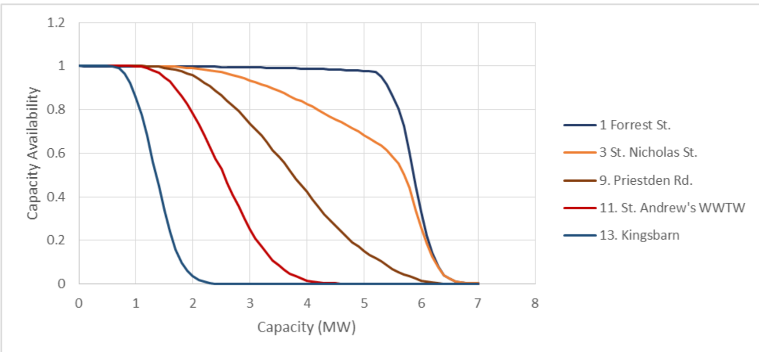
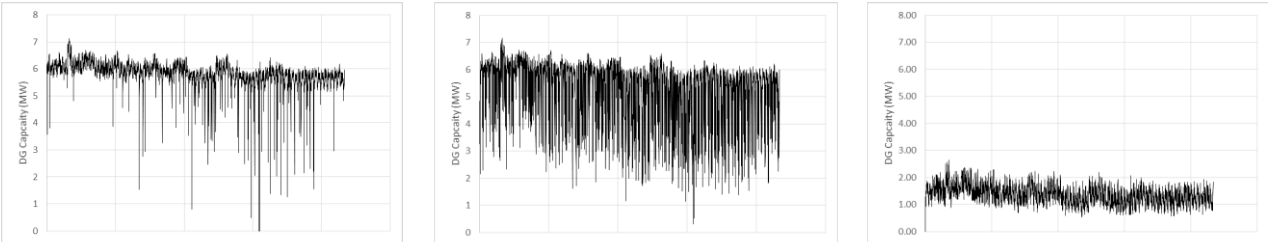



*Figure 13: Capacity duration curve showing network capacity available at 5 secondary substations. For a given network capacity, the figure shows the fraction of time that at least that level of network capacity is available.*

The capacity availability curve for Forrest St. which is close to the primary shows that 5MW of network capacity is almost always available. This reflects the fact that Forrest St. is thermally constrained the majority of the time with a limit set by the feeder thermal limit and the current demand.

Figure 14 shows how these availability duration curves relate to the associated time-series. At Forrest St. the thermal limit leads to a relatively small variation in capacity during most time-steps, with occasional downward spikes when particularly high primary voltages lead to voltage constraints becoming binding. At St. Nicolas Street, the thermal constraint defines the upper edge of the envelope of available capacity, however voltage constrains are binding during significantly more time-steps than is the case for Forrest St. Finally, at Kingsbarns at the end of the feeder, all time-steps are voltage constrained, and the significantly lower available capacity is shown by plotting the results on the same scale as for Forrest St. and St. Nicolas St.




(a) 1. Forrest St. (b) 3. St. Nicolas St (c) 13. Kingsbarns

*Figure 14: Time series of available network capacity at three substations for April – June 2014.*

## 3.3 Firm capacity estimates

The firm capacity available at each substation, if strictly defined, is the lowest capacity calculated during any time-step. In the current analysis this gives a very low value due to periods where the primary voltage is exceptionally high – that is around 11.25V or higher. For example, at Forrest St. and Hamilton Ave. the firm capacity under this definition is zero because the voltage at these points, during at least 1 time-step is higher than 11.25kV even with no DG connected. To give a more realistic picture of the potential firm capacity a definition is proposed here based on the 99$^{th}$ percentile meaning the network capacity available for 99% of the time. This excludes the lowest 1% of time-steps for each substation therefore removing those time-steps with exceptionally high primary voltages. This second definition takes account of the fact that then limit of 11.25kV is not a statutory legal limit, but an operating principle used by SPEN to manage the overall network, as such occasional breaches of the rule may be acceptable.

A point of comparison for either method of determining the firm capacity limit is to compare with heuristic a rule of thumb used by SPEN referred to here as the 'rule of 4'. This heuristic estimate of available capacity states that the firm capacity multiplied by the distance from the primary should be less than or equal to 4:

$$P_{firm} \times D_{primary} < 4$$

Where $P_{firm}$ is measured in MW and $D_{primary}$ is measured in km.

Figure 15 plots the 99$^{th}$ Percentile capacity, the Rule of 4 and the absolute minimum capacity along the feeder. Close to the primary the rule of 4 and the 99$^{th}$ Percentile give similar estimates of firm capacity, whilst the absolute minimum gives a very low estimate. Further along the feeder both the absolute minimum and 99$^{th}$ Percentile give estimates slightly higher than the rules of 4. As with other results in this report it should be remembered that the modelled estimates of firm capacity are based on only three months of data. Table 1 gives the values calculated for each substation.

*Table 1: Maximum and Minimum DG capacities at each secondary substation during April 2014*

| Substation | Distance from Primary | Max DG capacity (MW) | Min DG Capacity (MW) | 99th Percentile DG Capacity (MW) | 'Rule of 4' Capacity (MW) |
|---|---|---|---|---|---|
| Forrest St | 0.83 | 7.14 | 0.00 | 3.57 | 4.80 |
| Hamilton Ave | 1.13 | 7.14 | 0.00 | 2.78 | 3.54 |
| St Nicholas Street | 2.49 | 7.16 | 0.31 | 1.95 | 1.61 |
| Abbey Walk | 2.92 | 7.16 | 0.51 | 1.89 | 1.37 |
| Harbour Pumping Station | 3.13 | 7.10 | 0.60 | 1.85 | 1.28 |
| Gatty Marine | 3.56 | 7.06 | 0.73 | 1.76 | 1.12 |
| St Andrews Swimming Pool | 4.08 | 6.93 | 0.83 | 1.67 | 0.98 |
| St Nicholas WWTW | 4.18 | 6.85 | 0.84 | 1.64 | 0.96 |
| Priestden Road | 4.72 | 6.71 | 0.90 | 1.54 | 0.85 |
| East Grange | 5.54 | 5.37 | 0.96 | 1.35 | 0.72 |
| St Andrews WWTW | 7.65 | 5.04 | 0.95 | 1.19 | 0.52 |
| St. Andrews Bay Hotel | 11.24 | 3.71 | 0.71 | 0.92 | 0.36 |
| Kingsbarns | 18.03 | 2.66 | 0.54 | 0.68 | 0.22 |

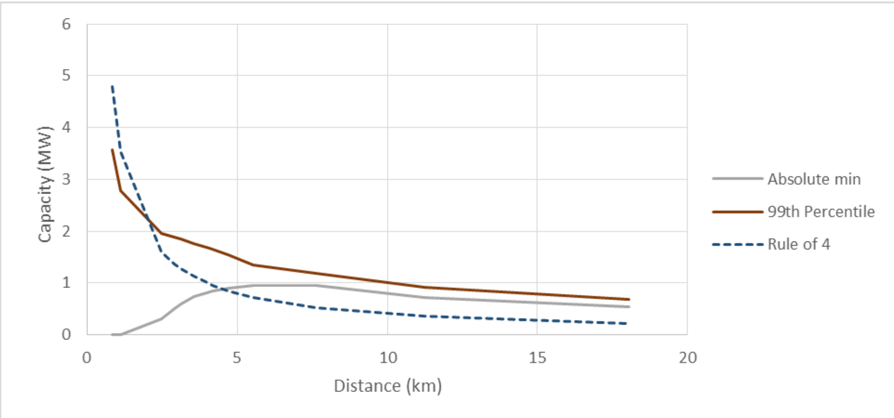



*Figure 15: Comparison between the 99th Percentile Capacity and the 'Rule of 4' capcaity for substations along Feeder 25 derived from data for April 2014.*

## 3.4 The effect of multiple generators

The calculations carried out in Sections 3.2 and 3.3 are for the situation where only 1 DG is connected to the feeder. Therefore the capacity calculated at each secondary substation is independent of the capacity calculated at all other substations. An important part of understanding the operation of a voltage constrained feeder is to consider the interaction of more than one DG. The injection of power at one secondary substation will affect the voltage at all other secondary substations and will therefore affect the remaining capacity for DG at those other substations.

As a simple example, if a DG injects the power at Substation 6 raising the voltage here close to 11.24kV, which is close to the limiting value, voltages at Substation 5 and 7 will also rise meaning very limited capacity at either of these locations.

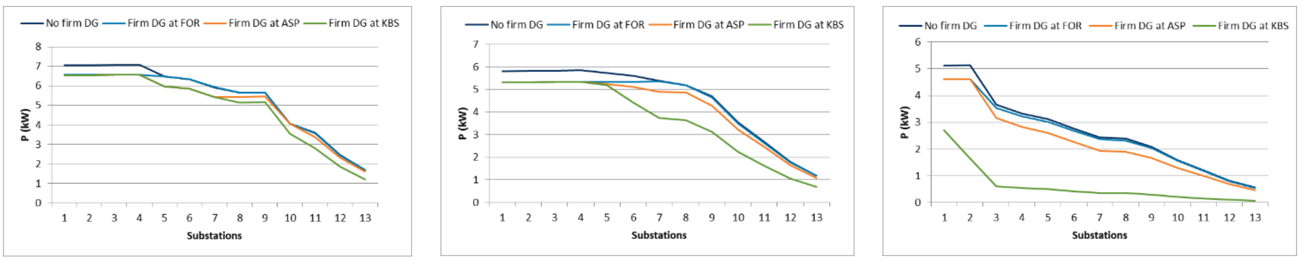
To investigate the effect of the interaction of two DGs, the method of Section 3.2 is adjusted to consider the remaining capacity for DG after the connection of a 0.5MW firm generator with a capacity factor of 1. The remaining capacity will be less than that calculated in Section 3.2, but it is interesting to identify the magnitude of the decrease, and the effect of the location at which the 0.5MW firm generator is connected.

To model this, an adapted version of the Power Factory feeder model has been created with the extra generator added to represent the firm generator. The resulting model is explained in Appendix A1.2. The methodology of Section 3.2 which was used to calculate the maximum DG capacity at each secondary substation and at each time step, described in Appendix A2.1, is also modified. In the new script, described in Appendix A2.2, the firm generator is first dispatched along with the historical demand, then the remaining capacity at each secondary substation is calculated. This script requires checking that the voltage remains within limits at both the point-of-connection of both the Firm and Non-Firm generators.

The method is carried out with the 0.5MW firm generator connected at 3 locations:

- Substation 1: Forrest St (FOR), close to the primary;
- Substation 7: St. Andrews Swimming Pool (ASP), in the middle of the feeder; and
- Substation 13: Kingsbarns (KBS), at the end of the feeder.

The effect on the remaining capacity for DG across the feeder is illustrated for three time-steps in Figure 16. The time-steps represent High, Intermediate and Low demand, respectively. In each case the capacity for DG without firm generation (as calculated in Section 3.2) is compared with the remaining capacity with the firm generator connected at each of the three potential locations.




(a) (b) (c)

*Figure 16: The effect of a 0.5MW firm generator on the remaining network capacity for DG when connected at three locations. Graphs show the capacity at each substation along the feeder for (a) High Demand, (b) Intermediate Demand and (c) Low Demand*

Substations which are thermally constrained see a reduction in the remaining capacity for DG of approximately 0.5MW if they remain thermally constrained after the addition of the firm generator. The firm generator effectively reduces the feeder demand by 0.5MW therefore reducing the available thermal capacity by 0.5MW. However, when a substation is constrained by voltage, it is not only the size of the firm generator but its location which affects the remaining capacity.

Figure 16 (c) shows the case of the low demand and relatively high Primary voltage, with substations 3 – 13 constrained by voltage with no Firm generator and substations 1 and 2 thermally constrained. The addition of the firm generator at either Substation 1 or 7 reduced the DG capacity at Substations 1 and 2 by approximately 0.5MW as expected. However the connection of the firm generator at Substation 13 reduces the DG capacity at Substations 1 and 2 by significantly more. This is because the voltage at Substation 13 is now close to 11.25V and only a small DG capacity can be accommodated elsewhere on the feeder before the voltage at Substation 13 reaches the limit. During some time-steps, this effect can reduce the available capacity elsewhere on the feeder to zero. In all three cases shown in Figure 16, locating the firm generator at Substation 13 leads to the greatest reduction in remaining network capacity elsewhere.

Whilst locating the firm generator at Substation 13 reduces DG capacity significantly, locating the firm generator at Substation 1 has an almost negligible effect on capacity at voltage constrained buses. In Figure 16 (a) the connection of the 0.5MW firm generator at Substation 1 can be seen to reduce the remaining capacity at thermally constrained Substations (1 to 4) by 0.5MW as expected. However, from substations 5 – 13 the addition of the firm generator does not reduce the remaining capacity. This means the feeder can support the original DG capacity at these locations *and* the 0.5MW firm generator. The reason is that the firm generator is close to the primary where the voltage is fixed. Injection of 0.5MW at Substation 1 therefore doesn't significantly affect the voltage profile across the feeder.

A useful way to visualise the competing effects is to consider the reduction in total capacity as a fraction of generation from the firm generator. During 1 half hour time-step the firm generator will inject 0.25MWh of electrical energy onto the network, or 1.08GWh over three months. The reduction of capacity available for other generators can then be benchmarked against this value.

Figure 17 plots the capacity reduction in this way for the three firm generator locations. A value of 1 reflects the situation where the reduction in network capacity exactly balances the output of the firm generator. This represent a neutral condition: the firm generator is efficiently using network capacity. If the value is greater than 1, the reduction in network capacity is greater than generation from the firm generator and conversely if less than 1 the reduction in network capacity is less than the energy injected by the firm generator. For values less than 1 the results is an overall greater capacity for DG than may have been expected from the results in Section 3.2.

By definition the fractional capacity reduction will be exactly 1 at the substation where the firm generator is connected. For example with the firm generator connected at Substation 7, network capacity reduction at Substation 7 is exactly 1. However, it is interesting to note that when the firm generator is at Substation 1, the reduction in network capacity is always less than 1 at substations 2 – 13, dropping to close to zero at the end of the feeder: connecting a generator at Bus 1 has a negligible impact on the capacity for DG at the end of the feeder. This therefore represents a highly efficient use of the network.

By contrast, connecting the firm generator at Bus 13 leads to a situation where the network capacity reduction at Substations 1 – 12 is greater than 1, rising to nearly 3 in the middle section. This highlights the inefficiency of connecting generation at the end of the feeder on the overall ability to connect more generation to the feeder.

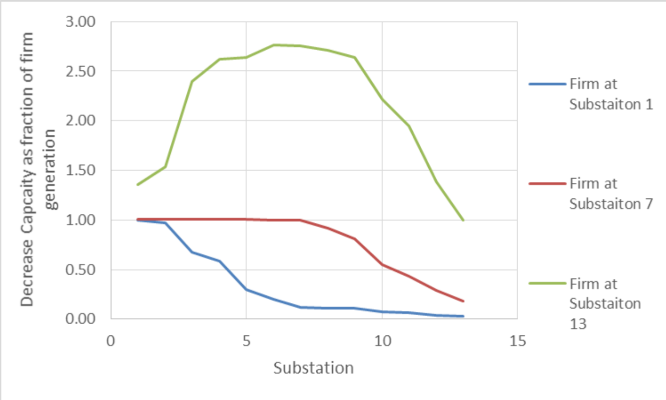



*Figure 17: Reduction in network capacity due to a firm generator, where reduction in capacity is expressed as a fraction of the energy injected from the firm generator.*

The conclusion from Figure 13 is that DG should be connected as high up the network as possible to maintain additional capacity. In an ANM situation the findings suggest that non-firm generation closer to the primary should have a higher priority. The connection of a DG can be thought of as imposing an 'opportunity cost' equal to the reduction in remaining capacity for DG. The connection of DG near the primary therefore has a small opportunity cost, whilst the connection of DG near the end of the feeder has a high opportunity cost.

Further understanding the interaction of multiple generators, and investigating the interaction of non-firm generators with various principles of access will form an important aspect of further work.

# 4 Task 3: Managing constrain voltages

Voltage limits have been shown in Section 3 to place a significant limit on the capacity of DG which can connect to an 11kV feeder. This is partly due to the operating principles currently in use to ensure the security of the network. There are a number of options to move away from the existing operating principles, and these are explored in this section.

Two specific examples are given. Firstly, the effect of increasing the limit on the point-of-connection voltage is investigated. Secondly, the use of demand flexibility or new electrical to raise demand at different point on the feeder. The objective of this section is to highlight the potential increases in DG capacity that these two interventions can create.

## 4.1 The effect of raising the point-of-connection voltage limit

The analysis carried out in the previous section and reported in Sections 3.2 and 3.3 was based on a point-of-connection limit of 11.25kV. To investigate the effect of raising this limit, the process is repeated using the same historic demand profiles with the point-of-connection limit raised to 11.3kV. The effect of this 50V increase is to allow greater capacity to connect to any substation that is voltage constrained, whilst substations that were originally thermally constrained will remain so in the new simulations.

Figure 18 shows the effect during the High and Low demand time-step illustrated earlier in Figure 12. The thermally constrained capacities at the first two substations remain unchanged. In the middle regions of the feeder at Substation 6 the capacity increases by 1.02MW for the High Demand case and 1.19MW for the low demand case. At the extremities of the feeder, the increase is relatively small with an increases of 200kW 280kW respectively for the High and Low Demand.

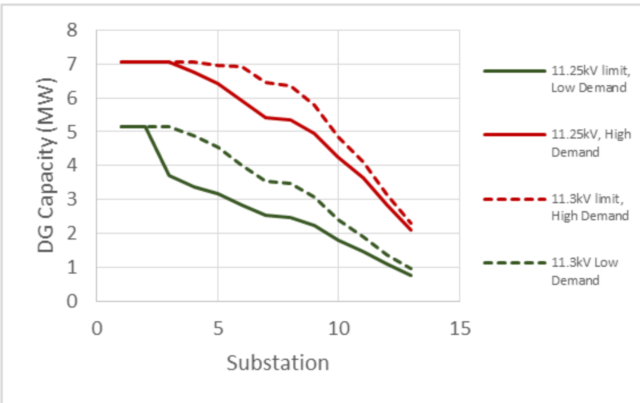



*Figure 18: Comparing the capacity along the feeder with a point-of-connection voltage limit of 11.25kV and 11.3kV.*

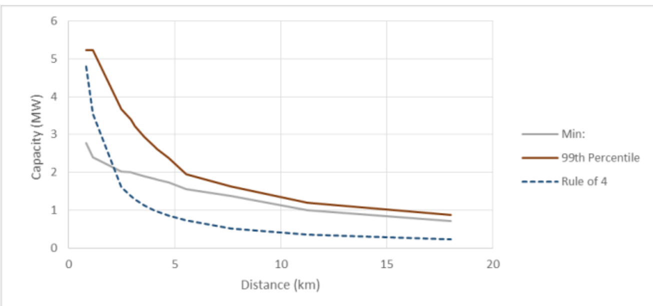



*Figure 19: Methods of Estimating the Firm Capacity when the point-of-connection is raised to 11.3kV*

The increase in firm capacity as estimated by either the 99th Percentile of available capacity and the absolute minimum capacity are shown in Figure 19 and Table 2. Raising the voltage limit removes the effect of very high primary voltages on firm capacity at substations close to the primary. The greatest increases are seen in the first half of the feeder with the additional capacity created greater than 1MW as far out as Substation 6, Gatty Marine, which is 3.56km from the primary.

*Table 2: Increase in the Firm Capacity when raising the point-of-connection voltage limit from 11.25kV to 11.3kV as estimated by the absolute minimum capacity and the 99th Percentile capacity. All values are in MW*

| ***Substation*** | ***1*** | ***2*** | ***3*** | ***4*** | ***5*** | ***6*** | ***7*** | ***8*** | ***9*** | ***10*** | ***11*** | ***12*** | ***13*** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Increase (Absolute Min) | 2.78 | 2.40 | 1.71 | 1.50 | 1.38 | 1.17 | 1.00 | 0.97 | 0.83 | 0.61 | 0.43 | 0.28 | 0.18 |
| Increase (99th Percentile) | 1.66 | 2.45 | 1.72 | 1.51 | 1.38 | 1.18 | 1.00 | 0.97 | 0.83 | 0.61 | 0.43 | 0.28 | 0.19 |

Increasing the allowed 11kV voltage level has the potential to impact on LV voltages. At locations where LV voltages are close to the upper bound of 253V per phase, increases 11kV voltages may create more cases of overvoltage. As discussed in Section 2, the only substation with significant instances of overvoltage is currently Priestden Road where 25% of voltages on Phase A are over 253V. Over the whole feeder only 0.6% of all LV voltage measurements collected by FlexNet for this period are overvoltage. Another 3% of voltages were recorded in the range 250V – 253V representing voltages that are close to the upper limit and in danger of being pushed over by increased 11kV voltages.

## 4.2 Increasing Demand – The ability of flexible demand to increase capacity for distributed generation

A second way to increase capacity for DG is to increase demand. This can either be through the development of new electrical demand, for example converting a non-electrical energy demand such as oil-heating, to electricity and aiming to supply it with renewable electricity from distributed generation. A second potential demand-side involvement is the use of flexible demand that can change the timing of electrical demand to relieve curtailment.

If demand and generation are on the same site, an increase in demand during a particular time-step will give a 1:1 relationship with capacity for DG: 1kW of additional demand reliving curtailment by 1kW. However, it is possible that the flexible demand may be located elsewhere on the feeder, for example if demand is distributed through a village and spread across multiple secondary substations. A methodology has therefore been developed which identifies the increase in DG capacity created at a particular secondary substation *if demand is increased at a different secondary substation.* The methodology increases demand by 100kW at different locations on the feeder and calculates the increase in DG capacity at a particular secondary. Details of the methodology can be found in Appendix A2.3 which describe the Power Factory script developed for this activity.

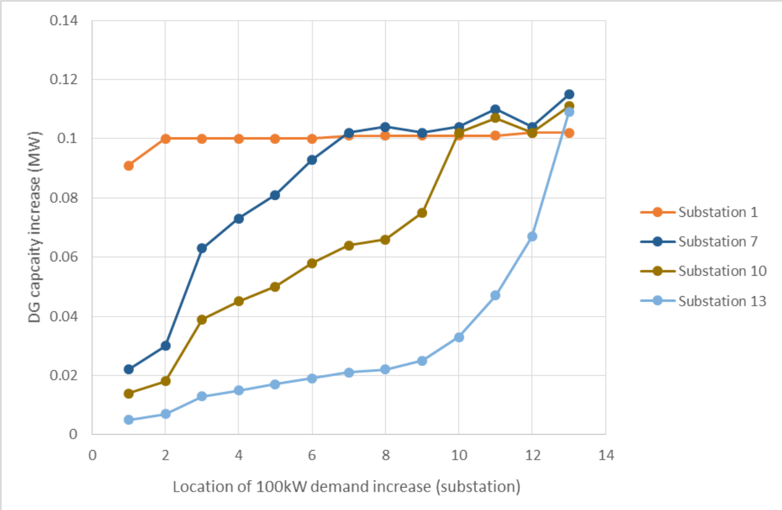



*Figure 20: Additional DG capacity creased due to increase in demand during a single time step. Each line represents DG capacity increase at a particular feeder location when demand is added at different substations.*

Figure 20 shows the results for a single time-step and for DG capacity at four secondary substations. The line for Substation 1 shows the additional DG capacity created when 100kW of demand is added at each secondary substation. The conclusion from this line for substation 1, the addition of 100kW of demand at any substation will allow an additional 100kW of DG capacity during that time-step. If a constrained generator were presented at Substation 1, the additional demand would therefore have the potential to reduce curtailment on a 1:1 basis no matter what the location of the demand. During this time-step Substation 1 is thermally constrained and any therefore additional demand would reduce reverse power flow from the feeder to the primary substation on a 1:1 basis[5].

For the other DG locations shown in Figure 20, the binding constraint is due to voltage. In these cases, the effectiveness of additional demand at creating further headroom for DG depends on its location. For DG located at Substation 13 that is at the end of the feeder additional demand located closer to the primary has a small than 1:1 effective: 100kW of additional demand leads to less than 100kW of extra DG capacity.

The results shown in Figure 20, which are replicated at all time-steps can be summarised as follows:

- Additional demand at the same secondary substation as a DG will raise capacity for that DG on a 1:1 basis.
- For substations where DG is thermally constrained, the addition of additional demand leads to approximately a 1:1 increase in DG capacity regardless of the location of the DG.
- Where DG capacity is voltage constrained, additional demand located closer to the primary than the DG unit will have a small than 1:1 effect on DG capacity, so every unit of additional demand creates less than 1 unit of extra DG capacity.
- Where DG capacity is voltage constrained and the additional demand is located further from the primary than the DG unit, the demand creates approximately a 1:1 increase in DG capacity.

These conclusions suggest that the efficient use of flexible demand to relieve voltage constraint requires that demand flexibility is used to manage voltages between the demand and the primary rather than between the demand and the extreme of the feeder.

[5] As with other conclusions relating to thermal constraints, changes in the electrical losses mean that there will be small variations away from the exact results, however these variations will be small compared with the level of precision that the power system is operated to.

## 4.3 Other strategies for managing feeder voltages

There are a large number of ways of managing voltage profiles. These include the use of reactive compensation, or controlling the power factor or reactive power injection of components on the network. There are also new technologies, or existing technologies which are becoming cheaper. One of these is the use of OLTC at secondary substations which can be used to control the LV voltage independent of the 11kV voltage.

Many of these are being tested in other projects around the UK. The majority of them are beyond the scope of the ARC project. One further intervention which may be used within ARC to increase voltage-constrained DG capacity is to change the control settings at primary transformers. Specifically it may be possible to lower the primary voltage as long as this can still be guaranteed to keep the network, out to the extremes of the LV network above the minimum voltage threshold.

Modelling and analysis of such a scheme will require a UoS to develop greater understanding of the existing and proposed control systems for LV models. This will include verifying a model of the 33/11kV transformer and understanding the set-points, dead band, and delays associated with the OLCT control system. One useful observation of the FlexNet data is that the lowest LV voltage recorded over Feeder 25 is 218, just above the lower statutory limit of 216V (based on a -10% limit). The number of instances of voltage records less than 227V which would form the lower bound if limits were tightened to a -6% limit is 21 out of more than 200,000. The FlexNet readings are made at the Secondary Substation, and it is important to ensure that LV voltages are above the minimum limit at the end of the LV feeders. SPEN operate the LV network with a maximum voltage drop along the feeder. This maximum voltage drop can therefore be applied to LV voltage measurements, and this analysis can form part of future work.

# 5 Non-firm connection Agreements

A key tool in ANM is the use of non-firm connection agreements where a DG accepts a connection on condition that it will reduce its output when instructed to do so by the network operator to maintain network limits. To date a number of schemes have used ANM and non-firm connection agreements to manage thermal limits, particularly on the 33kV network. The same principle can be applied to voltage constrained feeders.

For a given size of DG wishing to connect at a particular secondary substation, the expectation of curtailment can be estimated using historical times-series. Such a calculation requires (a) a time-series of the expected available generation and (b) a time-series of the available network capacity at that location. The network capacity time-series is an output of Task 2 as discussed in Section 3.2. The available generation time-series depends on the generation technology. For a wind generator, an existing method is to scale the historic output time-series for a nearby wind generator to the installed capacity of the non-firm generator in question. This assumes that the same wind resource is seen by both generators.

To illustrate this method, the network data for April – June 2014 is used to calculate the capacity of non-firm generation that can connect and should expect to have 10% of its potential output curtailed. This is referred to as $P^{nf}_{10\%}$, meaning the DG capacity available for non-firm wind with 10% curtailment. *It must be remembered that the results are only valid for 3 month of data and are included to show the methodology.*

Figure 21 shows the normalised available wind profile used in the study. The data is taken from a wind farm in the ARC region for the period January – March 2012. This is neither close to St. Andrews nor for the same time-period for which network data is available. As such it is strictly an illustration of the methodology. However, some of the results of the study are likely to be qualitatively useful in directing further studies of these effects.

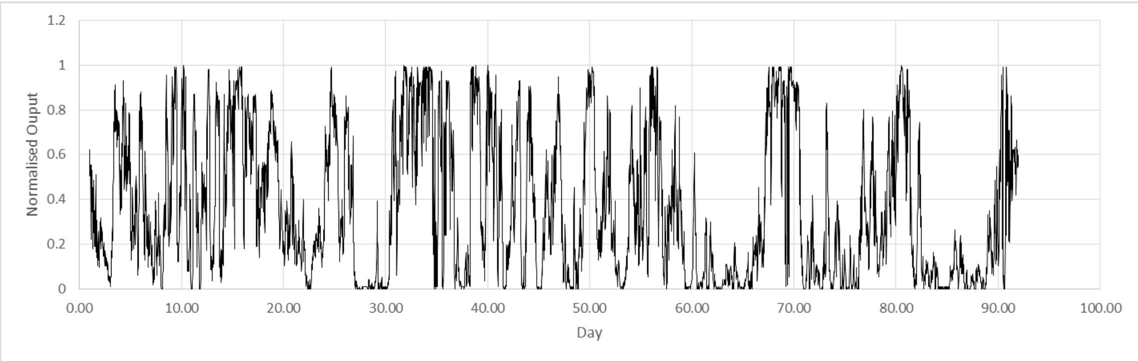



*Figure 21: Normalised available wind generation for a wind generator with an uncurtailed capacity factor of 0.36.*

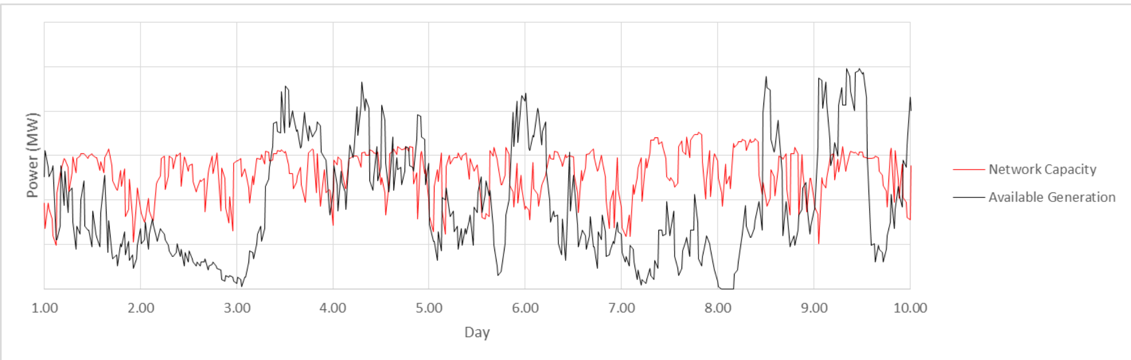



*Figure 22: Comparing network capacity against available wind generation for a 10 day period. Where the available generation (black) is greater than the network capacity (red) the generator is curtailed to the red line.*

Figure 22 shows an example of the calculation that should be carried out for a given capacity of generation connecting at a given network location. The red line shows the capacity of generation that the network can accommodate within thermal and voltage limits, and the black line shows the available generation. Where the black line is greater than the red line, curtailment is required. Ideally this calculation should be carried out for at least one full year of co-incident network and generation data before drawing firm conclusions.

To calculate the non-firm capacity at each secondary substation that will experience a 10% curtailment the following method is used:

1. For substation 1 (Forrest St.)
2. Retrieve the *available network capacity* time-series, $P_{network}(t)$, and the 99th percentile capacity, $P_{firm\ capacity}$, as calculated in Task 3.
3. Calculate the firm generation profile by scaling the normalised wind profile:
$$P_{firm}\ (t) = P_{firm\ capacity} \times P_{normalised\ wind}\ (t)$$
4. Calculate the remaining network capacity available to non-firm generation:
$$P_{non-firm}^{max}(t) = P_{network}(t) - P_{firm}\ (t)$$
5. Start with a small non-firm capacity of $P_{non-firm\ capacity} = 0.1MW$. Calculate the available non-firm generation profile by scaling the normalised wind profile:
$$P_{non-firm}^{available}(t) = P_{non-firm\ capacity} \times P_{normalised\ wind}\ (t)$$
6. Calculate how much curtailment is required for each time step to stay within the network limits
7. Calculate the fraction of available non-firm generation curtailment across the study
8. If the fraction of curtailed non-firm generation is less than 10% increase $P_{non-firm\ capacity}$ by 0.1MW and repeat steps 5 – 8.
9. Repeat Steps 2 – 8 for each secondary substation

The methodology has been developed as an excel spread sheet model. It connects firm capacity up to the 99th percentile limit, and then continues to connect non-firm capacity to the point at which the non-firm capacity experiences 10% curtailment.

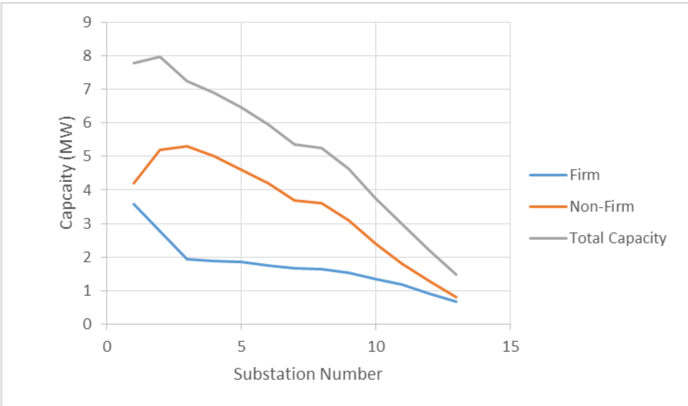



*Figure 23: Firm and non-firm capacity estimates for Feeder 25*

*Table 3: Estimates of Firm and non-firm capacity for Feeder 25*

| Substation | Firm Capacity (MW) | Non-Firm Capacity (MW) | Total Capacity (MW) |
|---|---|---|---|
| Forrest St | 3.57 | 4.2 | 7.77 |
| Hamilton Ave | 2.78 | 5.2 | 7.98 |
| St Nicholas Street | 1.95 | 5.3 | 7.25 |
| Abbey Walk | 1.89 | 5 | 6.89 |
| Harbour Pumping Station | 1.85 | 4.6 | 6.45 |
| Gatty Marine | 1.76 | 4.2 | 5.96 |
| St Andrews Swimming Pool | 1.67 | 3.7 | 5.37 |
| St Nicholas WWTW | 1.64 | 3.6 | 5.24 |
| Priestden Road | 1.54 | 3.1 | 4.64 |
| East Grange | 1.35 | 2.4 | 3.75 |
| St Andrews WWTW | 1.19 | 1.8 | 2.99 |
| St Andrews Bay Hotel | 0.92 | 1.3 | 2.22 |
| Kingsbarns | 0.68 | 0.8 | 1.48 |

Figure 23 and Table 3 show the illustrative estimates of capacity that can connect at each bus based on the three months analysis. As already noted these results are illustrative of the method rather than providing firm conclusions to draw for this network.

Whilst studies need to be carried out with at least one year of coincident data, the form of the results is sensible. Close to the primary substation, the firm capacity is large which itself limits the opportunity for non-firm capacity. However, in the middle region of the feeder firm capacity is limited by voltage constraints during a relatively few number of time-steps. For example substations 2 – 6 in the example are likely to provide the greatest opportunity for non-firm generators.

# 6 Task 5: Studying multiple feeders

The work presented for Tasks 1 – 4 is related to the management of thermal and voltage constraints on a single feeder fed from a primary substation. It makes a number of assumptions that are valid for the investigation of a single feeder, but not for the analysis of multiple feeders, effectively modelling the full 11kV network fed from a particular primary substation.

The work presented so far fixes the 11kV primary substation voltage to the historically recorded value. Whilst this allows the correct modelling of the historic network conditions including real and reactive power loading, the addition of distributed generation will lead to a change in the voltage at the primary substation. When only single DG or a single feeder is being investigated this change is held to a small value by the large load on other feeders. However, for the studies of the full distribution network with multiple generators added at different locations, the additional modelling is required.

This modelling will seek to understand the control of voltage at the primary by the transformers and associated on load tap changers, and the effect on demand drawn from the primary substation on the 33kV voltage level. In a simple example, a reduction of demand (or equivalently an increase in DG output) will initially lead to a rise in the voltage on the 11kV busbar as voltage drop on the 33kV system and through the primary transformers is reduced. However, at some point when the 11kV primary voltage reaches a predefined level for a predefined period, the on load tap changer will operate to reduce the voltage by changing the tap position.

Two types of modelling may be required. Firstly, a full dynamic analysis of situations where demand and DG output changes over time and the corresponding response of the on load tap changer. Secondly the ability to calculate the eventual steady state primary voltage from a more detailed Power Factory model, rather than relying on historically recorded values.

It is envisaged that this work will create an additional level of complexity which is beyond that already carried out. Before embarking on this stage of the modelling, UoS would like to engage with the wider ARC team to identify the further direction of this work.

As an example of the likely effect of removing the modelling requirement that the 11kV primary busbar is held at constant voltage, Figure 24 compares the DG capacity calculated for Feeder 25 in two cases: firstly with the 11kV voltage held constant and secondly with the 33kV voltage held constant but the 11kV voltage allowed to fluctuate. In the second case, the load associated with other feeders from St. Andrews Primary is included through a separate load of the 11kV primary busbar.

When the 11kV voltage is allowed to vary, the DG capacity calculated at all buses that are voltage constrained is reduced slightly. This is because the injection of power by the DG raises the 11kV voltage compared with the historic situation, therefore the remaining voltage head-room at the point-of-connection of the DG is reduced. The effect is greatest at locations closest to the primary where voltage is the binding constraint. When DG capacity is limited by thermal effects there is no difference between the two results, and at the far end of the feeder, the difference between the two results approaches zero. It is this effect, and where it begins to interact with the OLTC that needs further investigation.

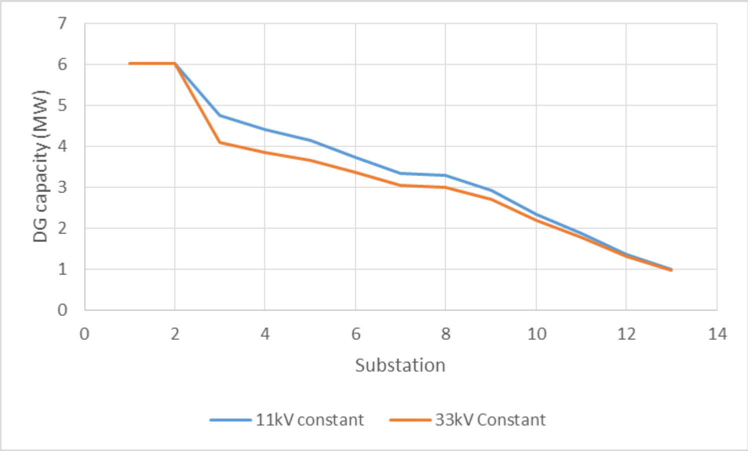



*Figure 24: Comparing DG capacity calculated with the 11kV voltage head constant against holding the 33kV voltage constant for an example time-step.*

# 7 Conclusions and next steps

The work presented in this report represents the development of detailed methodologies and Power Factory scripts to undertake analysis of the capacity of a voltage constrained 11kV feeder to accept DG connections. The following has been develop:

- Three different 11kV feeder models to test methodologies and to extract representative results.
- A methodology for identifying the time-series of DG capacity at each secondary substation on an 11kV feeder given a specific maximum voltage on the feeder.
- A methodology for identifying the reduction of DG capacity caused by the connection of 1 firm generator at a particularly secondary substation.
- A methodology for identifying the increase in DG capacity caused by the increase of demand at each location.

The work also presents tentative results from 3 months of data from the period April – June 2013. The overall results and conclusions are listed below:

- Historically recorded primary voltage values range from 10.9kV – 11.3kV
- Historically recorded secondary, LV voltage values are within statutory limits for more than 99% of all reading. One phase of one secondary substation represents almost all the out of range voltages with 25% of measured voltage above the limit of 253V at this substation on Phase a.
- Considering the 11kV voltage profiles with a limit of 11.25kV, simulations suggest that the firm capacity when estimated by the 99$^{th}$ percentile capacity limit drop off with distance from the primary in a similar way to the heuristic ‘rule of 4’ although the simulations slightly more capacity at the end of the feeder.
- Raising the point-of-connection voltage limit from 11.25kV to 11.3kV has the potential to increase DG capacity. The increase in firm capacity can be more than 2MW at some secondary substations.
- The use of non-firm connection and active management of generator output against a fixed point-of-connection voltage limit has the potential to more than double DG capacity at some locations if the curtailment of non-firm generation is allowed to rise to 10% of potential output. The greatest potential for the use of non-firm connections is in the middle regions of the feeder.
- When more than one DG connects to a feeder, the location of the first generator affects the remaining capacities. Therefore the connection of DG at a particular secondary substation can be thought of as imposing an ‘opportunity cost’ in terms of the reduction in remaining network capacity. If the first generator connects close to the primary it has little effect on the capacity at the end of the feeder and a small opportunity cost leading to an efficient use of the network in terms of maximising DG connection capacity. However, if the first generator connects at the end of the feeder there is a large opportunity cost that leads to significantly restricting further connections which outweigh the benefits of the first generator.
- Additional demand can create additional capacity for DG. Analysis shows that this demand, in order to be effective at managing voltage constraints, need to be connected either at the same location as the DG, or further away from the primary. Additional demand connected between a DG and the primary substation has a smaller effect.

## 7.1 Further Work

This report highlights potentially useful avenues for further work in terms of identifying the best way to operate an 11kV feeder and network with large penetrations of DG. Within the report a number of areas of further development have been highlighted. These are:

- *FlexNet data:* The FlexNet data provides a useful bank of historic data for 11kV feeders. However there are a number of questions which require further information. Most importantly, the mismatch between monitored and simulated LV voltages should be understood. Secondly, the exact reason for the missing demand should be identified and particularly the reason for the significant quantity of 'missing' reactive power when secondary substation measurements are compared with those from the primary should be understood.

- *Power Factory model:* further study of the 11kV/433V transformers is needed to ensure that this section of the power factory model is correct. In addition, the model should be extended to include at least some of the 33kV network. This would allow the point at which voltage is held constant in the simulations to be varied and allow the 11kV to vary. Understanding the best way to do this, and how to model the OLTC requires both Strathclyde Analysts and SPEN engineers.
- The effect of lowering the Primary voltage should be investigated.

It is expected that further work will aim towards defining and justifying new operating principles in terms of the maximum DG capacity to connect at different locations on the 11kV feeder when non-firm contracts are used. This may involve analysing the situation where DG is curtailed or controlled based on local measurements of voltage but without an overarching coordinated control system. In this case, the expected capacity may be increased beyond the 'rule of 4' to a higher capacity, but at each capacity and each combination of multiple generators connected at different locations, a new rule should be devised and justified.

In addition to this extra work, a further area to explore is the applicability of learning from another relevant LCNF project: LV templates[6]. This project, carried out by Western Power Distribution, monitored the LV feeders and attempts to classify secondary substations into 'templates' which can then predict important aspects of its operation including daily demand profiles and daily voltage profiles. Initial analysis of the St. Andrews Feeder 25 substations suggests a large variation in the shape of demand profiles at secondary substation on a day-by-day basis. This highlights the need to test the applicability of conclusions from LV Templates.

It is proposed that further work will attempt to apply the LV templates model to the FlexNet data, and later ARC data to determine if the use of templates can be beneficial to understanding the DG capacity, and likely curtailment of non-firm voltage constrained generation.

[6] http://www.westernpowerinnovation.co.uk/LV-Templates.aspx

# Appendix 1: Description of the models

This appendix provides a brief summary of the models used by the University of Strathclyde during the modelling activities over the period April-July 2014.

## *A1.1 Basic model*

The basic Power Factory model is based on the original Power Factory model of Feeder 25 provided by SPEN. The model is a simplification of the real feeder and it has been matched as closely as possible to the information available on the design of the feeder.

The original model includes the feeder itself, secondary subsations with three-phase loads taken directly off the 11kV busbars, external grid acting as the swing bus connected to 11kV primary busbar, and some distributed generation. After comparing the components of the original model against SPEN's GIS based database, some of the components were adjusted to the required project types. A list of component modifications of the original model is given in Table 4 with changes highlighted.

The initial model also includes a number of distributed generation studies carried out by SPEN dated between December 2013 and April 2014. These were not necessary for the purpose of this work and such they have been removed from the model (red circles in Figure 25).

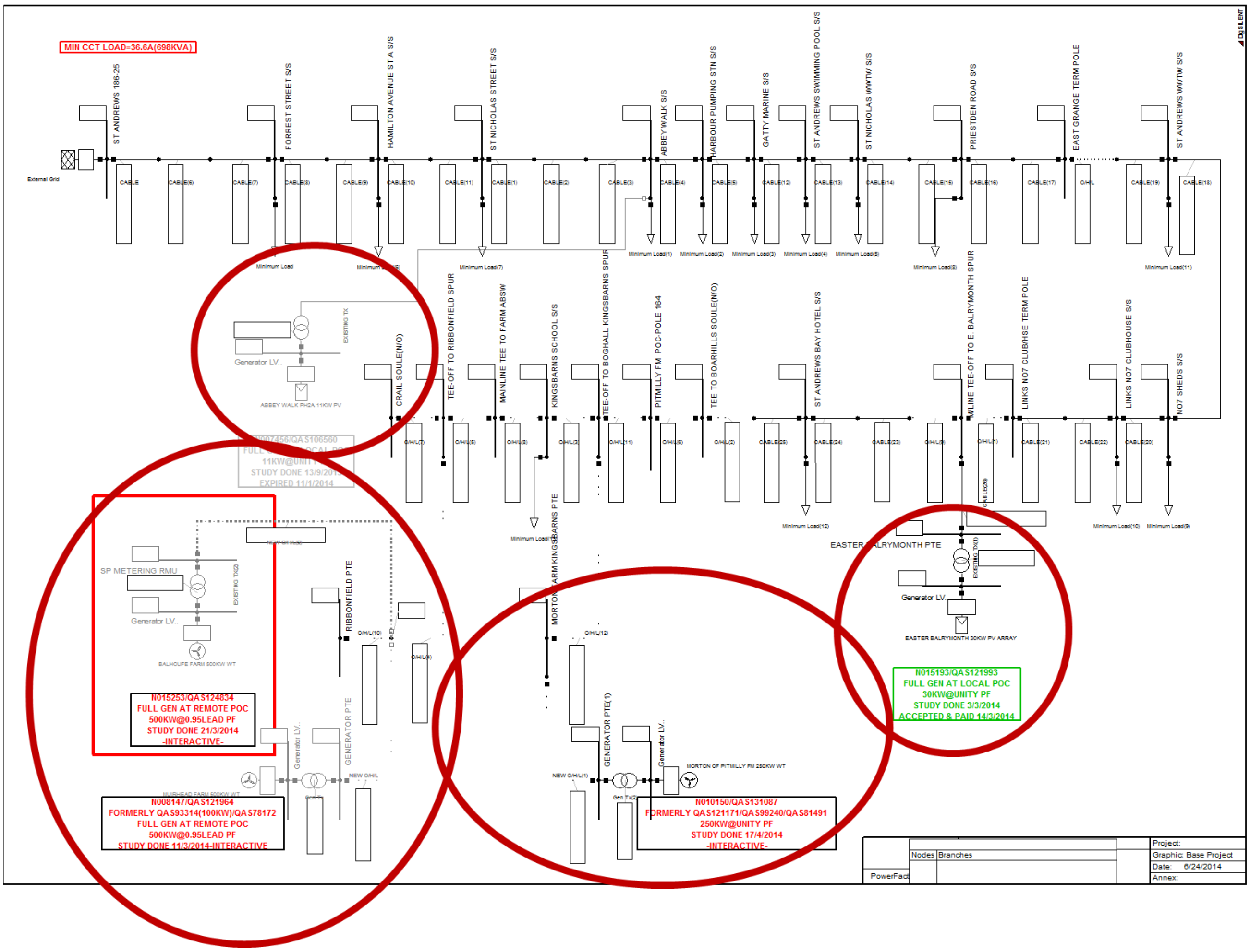



Figure 25: The original model of Feeder 25 provided by SPEN

*Table 4: Modifications to original Power Factory model to correct errors identified from GIS data. Changes are highlighted in Red.*

**Original Power Factory Model**

| *Substation* | *Line Order* | *PF component Name* | *PF component Type* | *Length (km)* |
|---|---|---|---|---|
| Pirmary | 1 | CABLE | Cable 11kV Al 185mm Coral.TypLne | 0.145 |
| | 2 | CABLE(6) | Cable 11kV Al 0.30in.TypLne | 0.044 |
| | 3 | CABLE(7) | Cable 11kV Al 0.15in.TypLne | 0.194 |
| Forrest St | 4 | CABLE(8) | Cable 11kV Al 185mm Coral.TypLne | 0.226 |
| | 5 | CABLE(9) | Cable 11kV Al 0.30in.TypLne | 0.07 |
| Hamilton Ave. | 6 | CABLE(10) | Cable 11kV Al 185mm Coral.TypLne | 0.007 |
| | 7 | CABLE(11) | Cable 11kV Al 0.30in.TypLne | 1.247 |
| St. Nicolas St | 8 | CABLE(1) | Cable 11kV Al 185mm Coral.TypLne | 0.006 |
| | 9 | CABLE(2) | Cable 11kV Cu 0.25in.TypLne | 0.355 |
| | 10 | CABLE(3) | Cable 11kV Cu 0.25in.TypLne | 0.68 |
| Abby Walk | 11 | CABLE(4) | Cable 11kV Al 185mm Coral.TypLne | 0.213 |
| Harbour Pumping St | 12 | CABLE(5) | Cable 11kV Al 185mm Coral.TypLne | 0.408 |
| | | | | |
| Gatty Marine | 13 | CABLE(12) | Cable 11kV Al 185mm Coral.TypLne | 0.532 |
| St Andrews Swimming Pool | 14 | CABLE(13) | Cable 11kV Al 185mm Coral.TypLne | 0.097 |
| St Nicolas WWTW | 15 | CABLE(14) | Cable 11kV Al 185mm Coral.TypLne | 0.095 |
| | 16 | CABLE(15) | Cable 11kV Al 0.25in.TypLne | 0.53 |
| Priestden Rd | 17 | CABLE(16) | Cable 11kV Al 185mm Coral.TypLne | 0.014 |
| | 18 | CABLE(17) | Cable 11kV Al 0.25in.TypLne | 0.724 |
| East Grange Term Pole | 19 | O/H/L | OHL 11kV SCA 150mm.TypLne | 1.337 |
| | 20 | CABLE(19) | Cable 11kV Al 185mm Coral.TypLne | 0.793 |
| St Andrews WWTW | 21 | CABLE(18) | Cable 11kV Al 185mm XLPE 3c.TypLne | 0.091 |
| No7 Sheds | 22 | CABLE(20) | Cable 11kV Al 185mm XLPE 3c.TypLne | 0.79 |
| | 23 | CABLE(22) | Cable 11kV Al 185mm XLPE 3c.TypLne | 0.381 |
| | 24 | CABLE(21) | Cable 11kV Al 185mm Coral.TypLne | 0.644 |
| | 25 | O/H/L(1) | OHL 11kV SCA 150mm.TypLne | 0.797 |
| | 26 | O/H/L(9) | OHL 11kV SCA 150mm.TypLne | 0.587 |
| | 27 | CABLE(23) | Cable 11kV Al 185mm XLPE 3c.TypLne | 0.014 |
| | 28 | CABLE(24) | Cable 11kV Al 185mm Coral.TypLne | 1.049 |
| ST Andrews Bay Hotell | 29 | CABLE(25) | Cable 11kV Al 185mm Coral.TypLne | 1.065 |
| | 30 | O/H/L(2) | OHL 11kV SCA 150mm.TypLne | 1.665 |
| | 31 | O/H/L(6) | OHL 11kV SCA 150mm.TypLne | 2.394 |
| | 32 | O/H/L(11) | OHL 11kV SCA 150mm.TypLne | 1.446 |
| | 33 | O/H/L(3) | OHL 11kV SCA 150mm.TypLne | 1.446 |
| Kingsbarn | | | | |

**Corrected Power Factory Model**

| *Substation* | *Line Order* | *PF component Name* | *PF component Type* | *Length (km)* |
|---|---|---|---|---|
| Primary | 1 | CABLE | Cable 11kV Cu 0.15in.TypLne | 0.2 |
| | 2 | CABLE(6) | Cable 11kV Al 0.30in.TypLne | 0.044 |
| | 3 | cablePinchPoint | Cable 11kV Al 185mm Coral.TypLne | 0.194 |
| Forrest St. | 4 | CABLE(8) | Cable 11kV Al 185mm Coral.TypLne | 0.226 |
| | 5 | CABLE(9) | Cable 11kV Al 0.30in.TypLne | 0.07 |
| Hamilton Av | 6 | CABLE(10) | Cable 11kV Al 0.30in.TypLne | 0.115 |
| | 7 | CABLE(11) | Cable 11kV Al 0.30in.TypLne | 1.247 |
| St. Nicolas St. | 8 | CABLE(1) | Cable 11kV Cu 0.30in.TypLne | 0.06 |
| | 9 | CABLE(2) | Cable 11kV Cu 0.25in.TypLne | 0.225 |
| | 10 | CABLE(3) | Cable 11kV Cu 0.25in.TypLne | 0.14 |
| Abbey Walk | 11 | CABLE(4) | Cable 11kV Al 185mm Coral.TypLne | 0.213 |
| Harbour Pumping St. | 12 | Line | Cable 11kV Al 185mm Coral.TypLne | 0.14 |
| | 13 | Line(2) | Cable 11kV Al 185mm Coral.TypLne | 0.29 |
| Gatty Marine | 14 | CABLE(12) | Cable 11kV Al 185mm Coral.TypLne | 0.52 |
| St. Andrews Swimming Pool | 15 | CABLE(13) | Cable 11kV Al 185mm Coral.TypLne | 0.097 |
| St Nicolas WWTW | 16 | CABLE(14) | Cable 11kV Al 185mm Coral.TypLne | 0.04 |
| | 17 | CABLE(15) | Cable 11kV Al 0.25in.TypLne | 0.5 |
| Priestden Rd. | 18 | CABLE(16) | Cable 11kV Al 95mm Coral.TypLne | 0.1 |
| | 19 | CABLE(17) | Cable 11kV Al 95mm Coral.TypLne | 0.724 |
| East Grange Term Pole | 20 | O/H/L | OHL 11kV SCA 150mm.TypLne | 1.337 |
| | 21 | CABLE(19) | Cable 11kV Al 185mm Coral.TypLne | 0.77 |
| St. Andrews WWTW | 22 | CABLE(18) | Cable 11kV Al 185mm XLPE 3c.TypLne | 0.091 |
| No7. Sheds | 23 | CABLE(20) | Cable 11kV Al 185mm XLPE 3c.TypLne | 0.33 |
| | 24 | CABLE(22) | Cable 11kV Al 185mm XLPE 3c.TypLne | 0.381 |
| | 25 | CABLE(21) | Cable 11kV Al 185mm Coral.TypLne | 0.644 |
| | 26 | O/H/L(1) | OHL 11kV SCA 150mm.TypLne | 0.797 |
| | 27 | O/H/L(9) | OHL 11kV SCA 150mm.TypLne | 0.587 |
| | 28 | CABLE(23) | Cable 11kV Al 185mm XLPE 3c.TypLne | 0.014 |
| | 29 | CABLE(24) | Cable 11kV Al 185mm Coral.TypLne | 1.049 |
| St Andrews Bay Hotel | 30 | CABLE(25) | Cable 11kV Al 185mm Coral.TypLne | 1.065 |
| | 31 | O/H/L(2) | OHL 11kV SCA 150mm.TypLne | 1.665 |
| | 32 | O/H/L(6) | OHL 11kV SCA 150mm.TypLne | 1.6 |
| | 33 | O/H/L(11) | OHL 11kV SCA 150mm.TypLne | 1.15 |
| | 34 | O/H/L(3) | OHL 11kV SCA 150mm.TypLne | 0.96 |
| Kingsbarns | | | | |

Each secondary substation is extended to include an 11kV/433V transfomer, LV busbar and LV load (the 11kV load is moved to the LV busbar). The size and impedence of the transformer at each secondary substation is set in line with information provided by SPEN (04/06/2014). An example of an extended secondary substation model is shown in Figure 26.

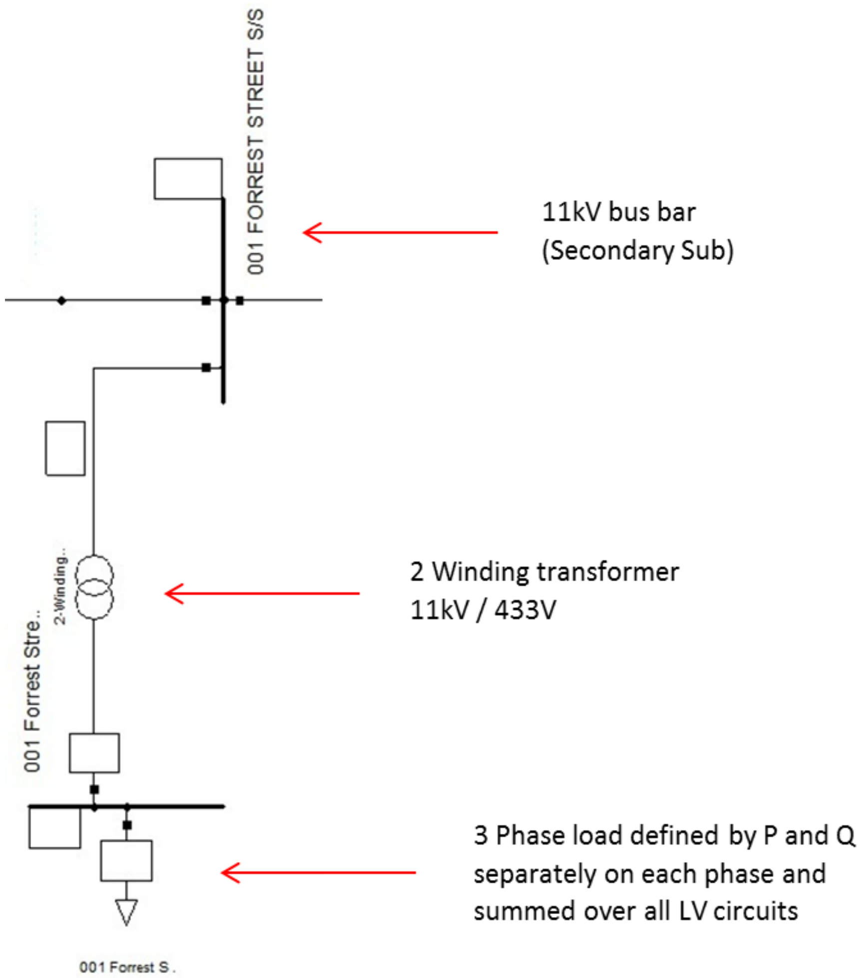



*Figure 26: Extended secondary substation*

Since the FlexNet Data used as an input data for the purpose of this work included demand data for 3 substations that are not provided in the original PF model, additional loads have been added. These are: The Shore, Allanhill, Kinkell Caravan Park, Borwnhills and Seagate. The Shore has been added as a second load at the Harbour Pumping Station Substation. Allanhill, Kinkell and Brownhills have been added to an extra secondary substation connected to the East Grange Terminal Pole. Seagate has been added as an extra load at Kingsbarns School substation. On the other hand, two secondary substations: No7 Sheds and No7 Clubhouse, have been removed from the original PF model since they did not correspond to the readings from Flexible Networks. Additionaly, for the purpose of modelling and writing scripts, all substation were renamed in the Power Factory model and Table 5 summarrizes all substation name changes with their loads.

*Table 5: Summary of substation names and their loads*

| Number | Original substation name | Power Factory substation name | Substation load name |
|---|---|---|---|
| | Primary | St. Andrews 186-25 | |
| 1. | Forrest Street | 001 Forrest Street S/S | 001 Forrest St Load |
| 2. | Hamilton Avenue | 002 Hamilton Avenue St A S/S | 002 Hamilton Ave Load |
| 3. | St. Nicholas Street | 003 St. Nicholas Street S/S | 003 St. Nicholas Street Load |
| 4. | Abby Walk | 004 Abby Walk S/S | 004 Abbey Walk Load |
| 5. | Harbour Pumping Station | 005 Harbour Pumping Stn S/S | 005 Harbour Pumping station Load<br>006 The Shore Load |
| 6. | Gatty Marine | 007 Gatty Marine S/S | 007 Gatty Marine Load |
| 7. | St. Andrews Swimming Pool | 008 St. Andrews Swimming Pool S/S | 008 St. Andrews Swimming Pool Load |
| 8. | St. Nicholas WWTW | 009 St. Nicholas WWTW S/S | 009 St. Nicholas WWTW Load |
| 9. | Priestden Road | 010 Priestden Road S/S | 010 Priestden Road Load |
| 10. | East Grange Term Pole | 011 East Grange Term Pole S/S | 011 Allanhill<br>012 Kinkell<br>013 Brownhills |
| 11. | St. Andrews WWTW | 014 St. Andrews WWTW S/S | 014 St. Andrews WWTW Load |
| | No7 Sheds | | |
| | Links No 7 Clubhouse | | |
| 12. | St. Andrews Bay Hotel | 015 St. Andrews Bay Hotel S/S | 015 St. Andrews Bay Hotel Load |
| 13. | Kingbarns School | 016 Kingbarns School S/S | 016 Kingbarns School Load<br>017 SeaGate Load |

Finally, as this model was used to study various DG scenarios, a 'shadow DG generator' is added to each secondary substation on the 11kV side with generation (P and Q) set to zero. These shadow DG generators were named in the model as 001 DG, 002 DG up to 016 DG with the reference number the same as the reference number of the secondary substation to which it connects. The final feeder model used in the study is shown in Figure 27 with red squares showing added 'shadow DG generators'.

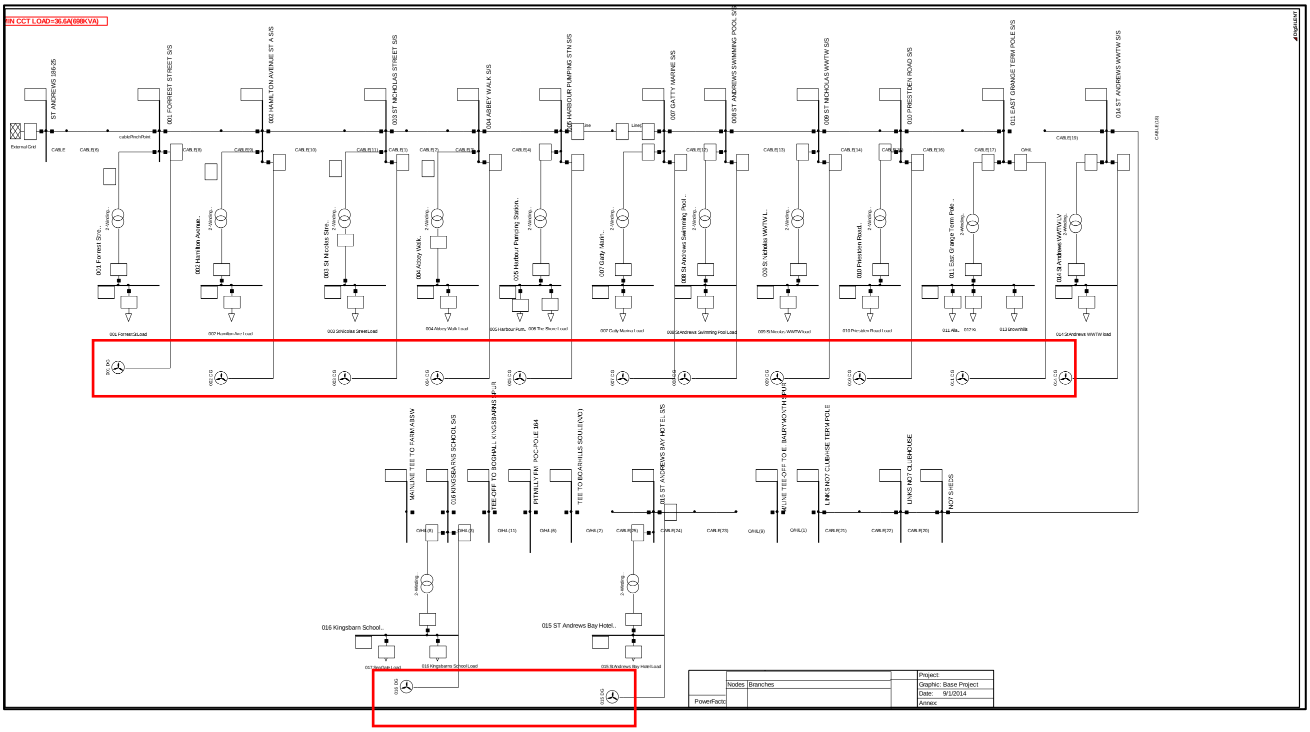


*Figure 27: Basic model used in this study*

### *A1.2 Model with firm generators*

This model is an extension of the basic model described above. The basic model was modified to connect one firm generator at full capacity at three locations on the feeder. Three 'shadow firm generators', named FDG1, FDG2, and FDG3,with generation (P and Q) set to zero are added to three secondary substations: 001 – Forrest Street S/S, 008 – St. Andrews Swimming Pool S/S, and 016 – Kingsbarns School S/S. The feeder model used in these study is shown in Figure 28 with red circles showing added 'shadow firm generators'.

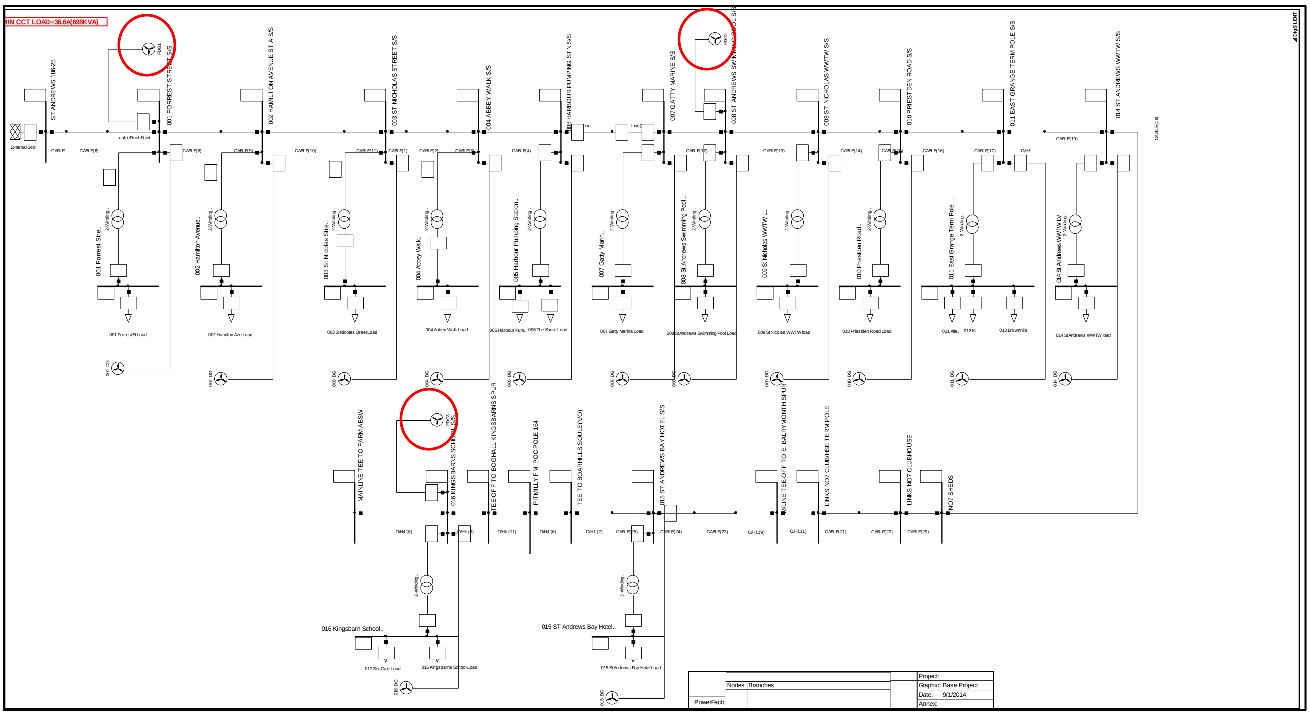


*Figure 28: Model with firm generators*

### *A1.3 Model with the additional HV section and the extra load to represent other feeders*

This model is an extension of the basic model described above. The basic model was extended at the start of the feeder (red circle in Figure 29) in order to include the 33kV busbar at St. Andrews Primary.

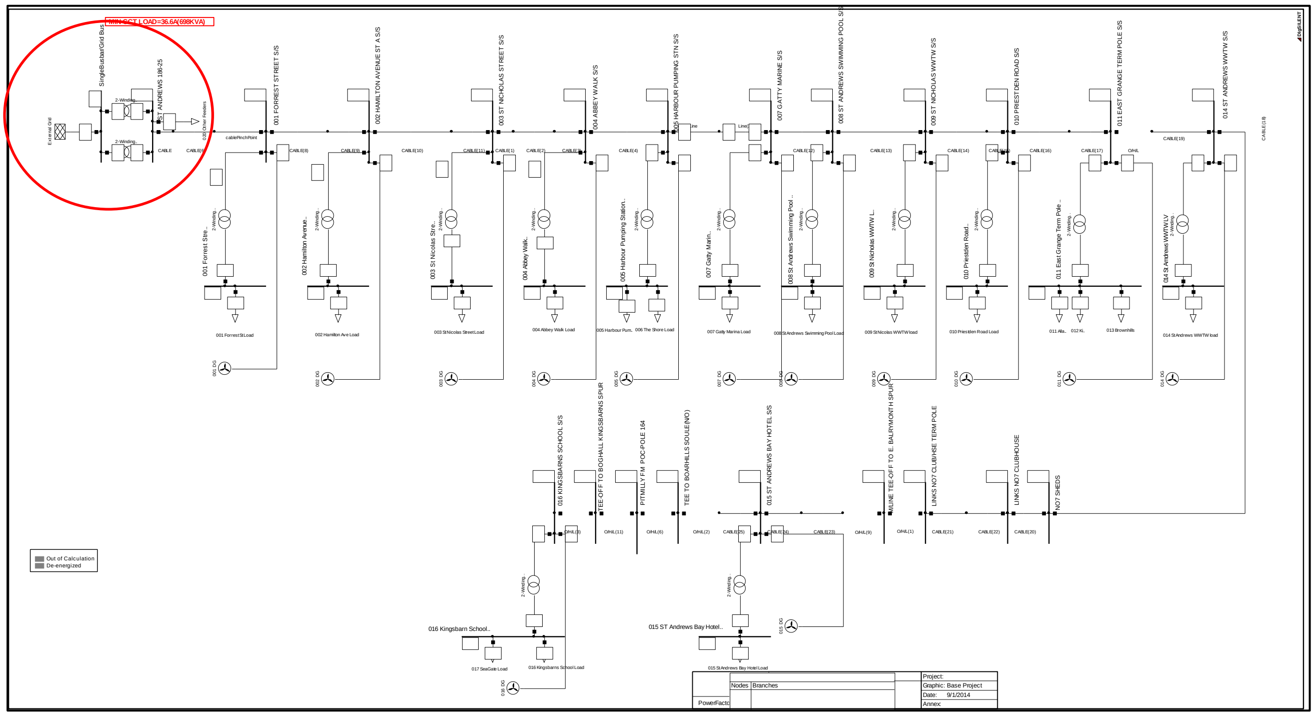


*Figure 29: Model with the additional HV section*

The adjusted section of the model is shown in Figure 30. The 33kV bus becomes the point of fixed voltage with the 'External Grid' feeding to this busbar. Two generic 2-winding 33kV/11kV transformers linking the 33kV and 11kV bars at the Primary are added at the start of the Feeder 25. Also, an extra load (named 020 Other Feeders) is used to represent demand on other feeders fed from St. Andrews Primary. This extra load is set to the total historically recorded demand on all other feeders from the primary.

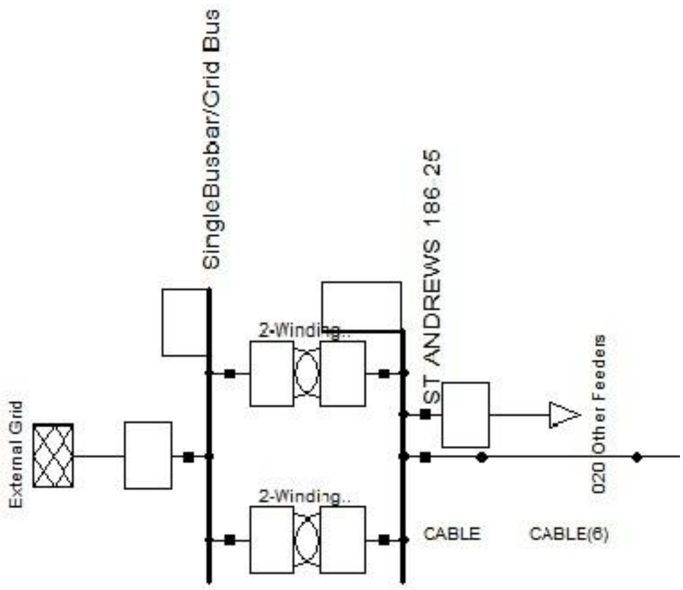



*Figure 30: HV extension and the extra load*

# Appendix 2: Summary of scripts developed during modelling studies

During the modelling activities undertaken over the period April-July 2014, the University of Strathclyde developed scripts which allow a better understanding of the problems that arise on the 11kV network while connecting distributed generators. All the scripts were developed by writing DIgSILENT Programming Language (DPL) script in Power Factory software. This appendix provides a brief summary of the scripts developed. All the scripts are used with the version of Feeder 25 which includes 11kV/433V transformers with loads modelled on the LV side.

## *A2.1 Study case: DG Capacity*

This study case uses the Power Factory model described in the Appendix A1.1 and the developed scripts are explained below.

### A2.1.1 Script: ThreePhaseTimeStep

This is the main script in this case study. The script opens a 'csv' input file with historical measurements of primary voltage and historical demand readings of three phase loads at each secondary substation for Feeder 25. It then sets the primary voltage and load values, the active and reactive power, to represent conditions at a particular time-step. The number of time-steps is equal to the number of days multiplied by 48, since we are using half hourly time-steps. The script calls *DG_capacity* script (see A2.1.2) to calculate the maximum DG capacity at each secondary substation. Finally, the script prints a number of completed time-step and closes input and output files.

The flowchart of the script is shown in Figure 31.

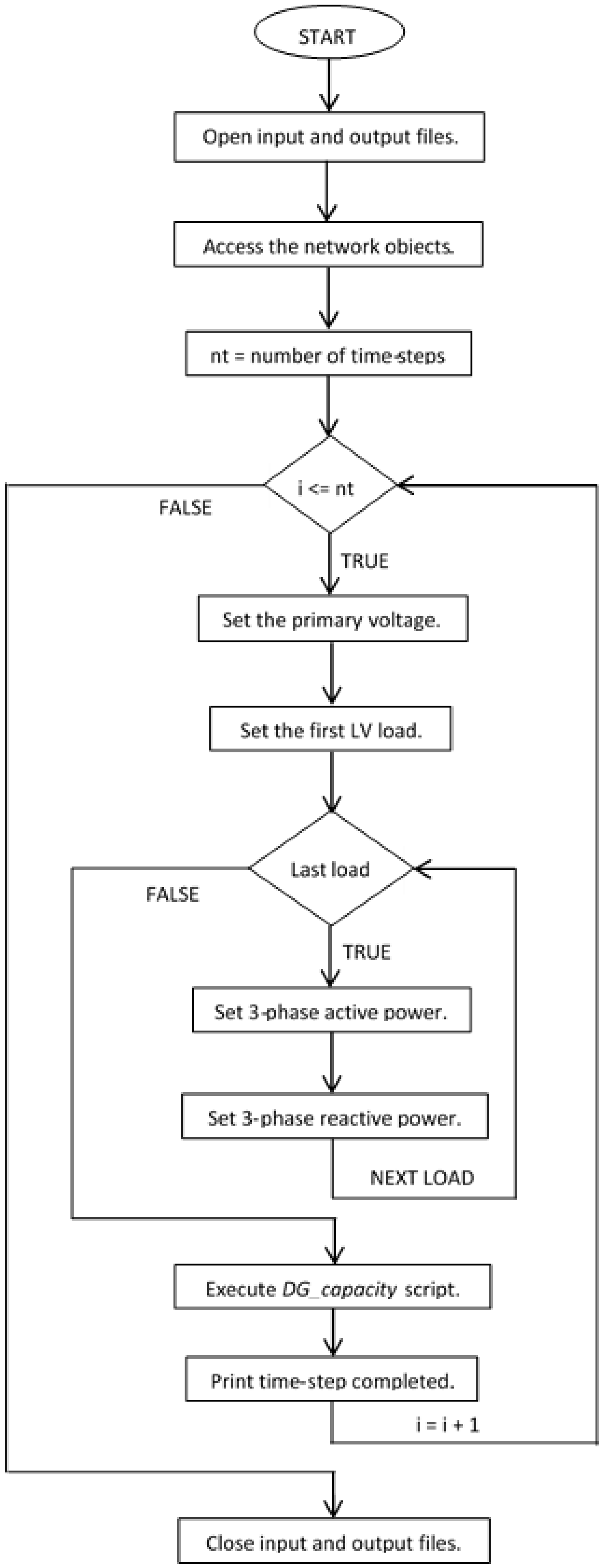



*Figure 31: The flow chart of the scrip ThreePhaseTimeStep*

### A2.1.2 Script: DG_capacity

The script calculates the maximum power injections available for a single DG at each secondary substation for the current demand conditions. It maintains thermal limits across the feeder and checks voltage limit at the point-of-connection of DG. The script loops around each bus in order to find the maximum DG capacity that can connect at each secondary substation. Calculated capacity at each bus assumes no DG connected at any other bus.

The script uses a binary search algorithm to find the maximum DG that maintains the local voltage limit of 11.25kV at the point-of-connection, and the thermal limit of all cables in the model. The load flow is calculated by executing the script *LoadFlow* (see A2.1.3) and the thermal loading of all cables by executing the script *checkCableLoading* (see A2.1.4). Assumed maximum DG capacity is in the range (0 – 10MW at each location). The starting point of the binary search is 5MW. From the existing guess, the DG capacity is either decreased or increased depending on whether constraints are breached or not. The initial step size for the increase/decrease is 2.5MW, i.e. half the initial capacity. Step size is reduced by 2 in each subsequent iteration. The convergence condition is that the difference between the upper and lower bounds on capacity (that is the lowest DG capacity that breaches the constraints and the highest DG capacity that does not breach the constraints) is less than 0.01MW.

Input parameters are: the load flow related to the active study case; set of all secondary substations in the model; set of all wind generators in the model; and an index of the output file in which the results will be written. The search returns the final lower bound, which is therefore guaranteed not to breach limits and to be within 0.01 of the actual limit.

The flowchart of the script is shown in Figure 32.

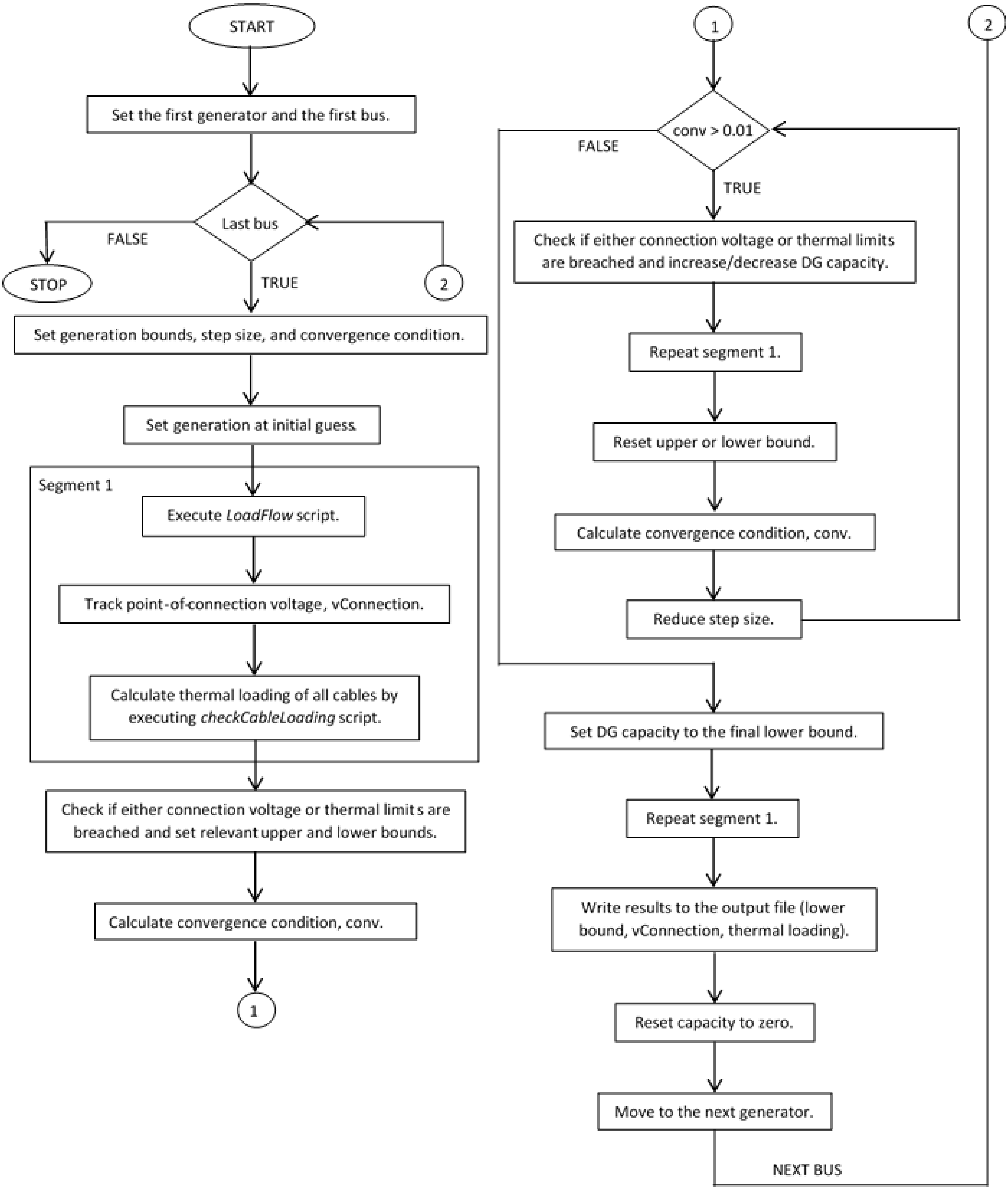



*Figure 32: The Flowchart for the script DG_Capacity*

### A2.1.3 Script: LoadFlow

The script calculates the load flow of the active case study. Both balanced and unbalanced load flow can be executed.

Input parameters are: the load flow related to the active study case; and type of the load flow – 0 for balanced and 1 for unbalanced load flow.

The flowchart of the script is shown in Figure 33.

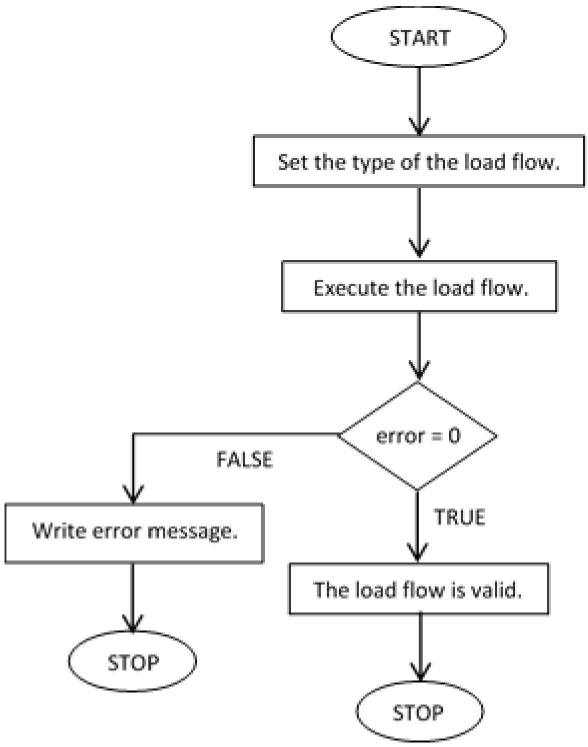



*Figure 33: The flow chart for the script LoadFlow*

### A2.1.4 Script: checkCableLoading

The script calculates maximum cable loading of all cables in the model.

The input parameter is the set of all cables in the model, and the output parameter is the maximum loading of all cables as a percentage of rated capacity.

The flowchart of the script is shown in Figure 34.

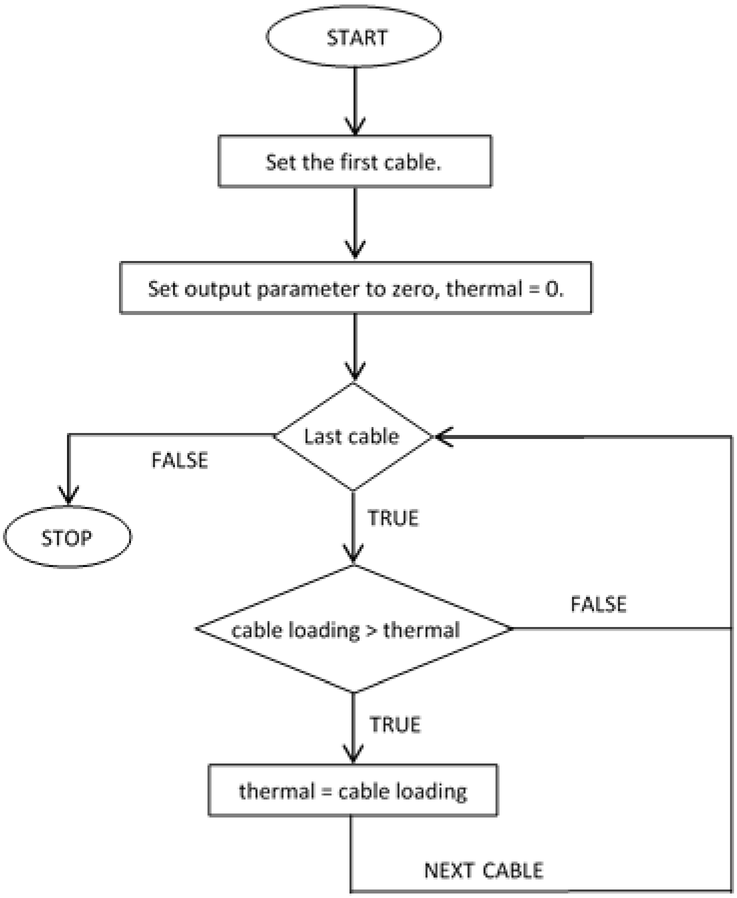



*Figure 34: The flow chart of the script checkCableLoading*

### *A2.2 Study case: Gen Interactions*

This study case uses the Power Factory model described in the Appendix A1.2 and developed scripts are explained below.

#### A2.2.1 Script: ThreePhaseTimeStepWithMultipleGen

The script is a modified version of the script *ThreePhaseTimeStep* shown in Figure 31. That script is adjusted to connect one firm generator at full capacity (0.5MW) at one of three possible locations on the feeder.

It opens a 'csv' input file with historical measurements of primary voltage and historical demand readings of three phase loads of each secondary substation for Feeder 25. It then sets the primary voltage and load values, the active and reactive power, to represent conditions at a particular time-step. The number of time-steps is equal to the number of days multiplied by 48, since we are using half hourly time-steps. The script dispatches the chosen firm generator at full capacity (0.5MW) and then calls *DG_capacityWithMultipleGen* script (see A2.2.2) to estimate the remaining capacity at each secondary substation for non-firm DG. The possible locations of added firm generator are the following three secondary substations: 001 – Forrest Street S/S; 008 – St. Andrews Swimming Pool S/S; and 016 – Kingsbarns School S/S. Finally, the script prints a number of completed time-step and closes input and output files.

The flowchart of the script is shown in Figure 35 with blue boxes presenting modifications of the script in Figure 31.

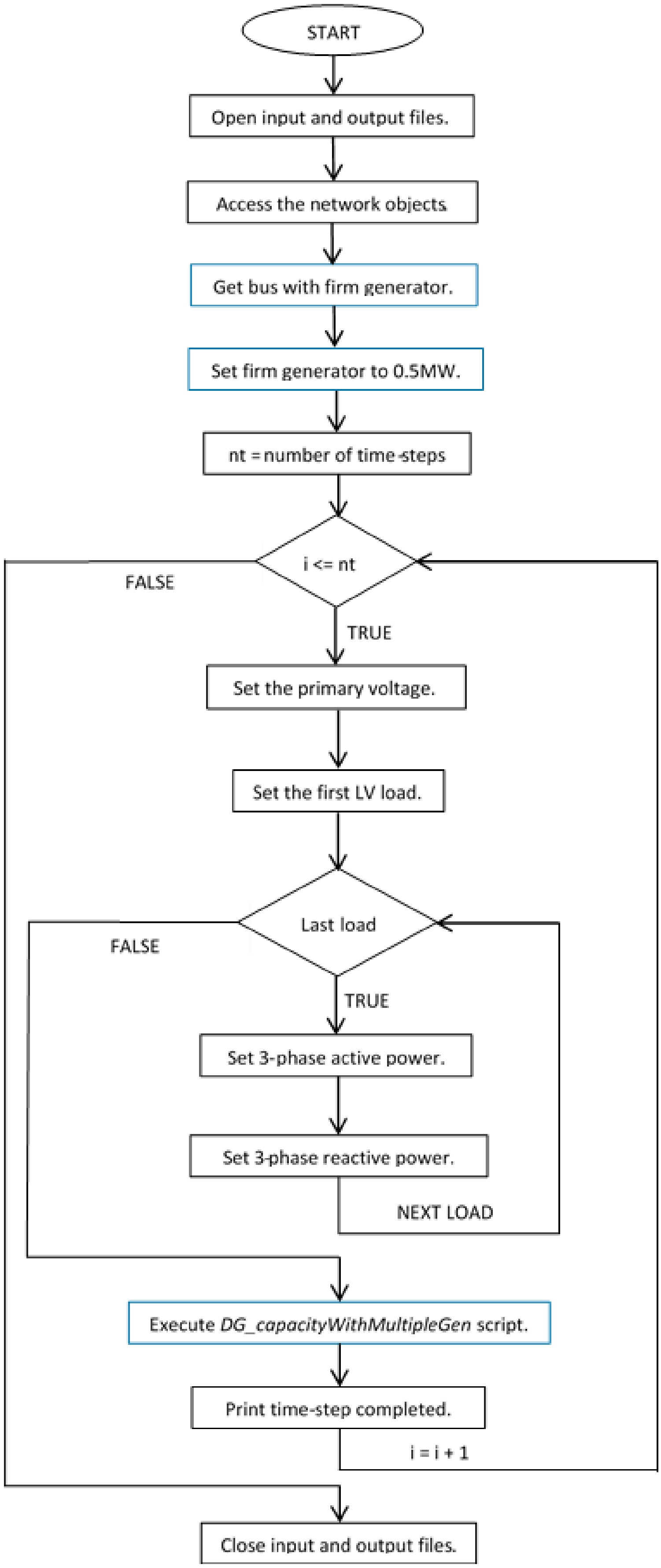



*Figure 35: The flow chart of the script ThreePhaseTimeStepWithMultipleGen*

### A2.2.2 Script: DG_capacityWithMultipleGen

The script is a modified version of the script *DG_capacity* shown in Figure 32. It is adjusted to consider the effect of a firm generator of capacity 0.5MW connected at one of three locations on the feeder.

The script calculates the maximum power injections available for a single DG at each secondary substation for the current demand conditions and with one firm generator enabled and generating at full capacity. It maintains thermal limits across the feeder and checks voltage limits of both firm generator and non-firm DG connection points. The script loops around each bus in order to find the maximum DG capacity that can connect at each secondary substation. Calculated capacity at each bus assumes one firm generator connected at the chosen bus in the system and no non-firm DG connected at any other bus.

The script uses a binary search algorithm to find the maximum DG that maintains the local voltage limit of 11.25kV at the point of both firm generator and non-firm DG connection, and the maximum thermal limit of all cables in the model. The load flow is calculated by executing the script *LoadFlow* shown in Figure 33 and the thermal loading of all cables by executing the script *checkCableLoading* shown in Figure 34. Assumed maximum DG capacity is in the range (0 – 10MW at each location). The binary search starting point for DG capacity is 5MW. From the existing guess, the DG capacity is either decreased or increased depending on whether constraints are breached or not. The initial step size for the increases/decrease is 2.5MW, i.e. half the initial capacity. Step size is reduced by 2 in each subsequent iteration. The convergence condition is that the difference between the upper and lower bounds on capacity (that is the lowest DG capacity that breaches the constraints and the highest DG capacity that does not breach the constraints) is less than 0.01MW.

Input parameters are: the load flow related to the active study case; the set of all secondary substations in the model; the set of all wind generators in the model; the bus with firm generation connected; and an index of the output file in which the results will be written. The search returns the final lower bound, which is therefore guaranteed not to breach limits and to be within 0.01 of the actual limit.

The flowchart of the script is shown in Figure 36 with blue boxes presenting modifications of the script in Figure 32.

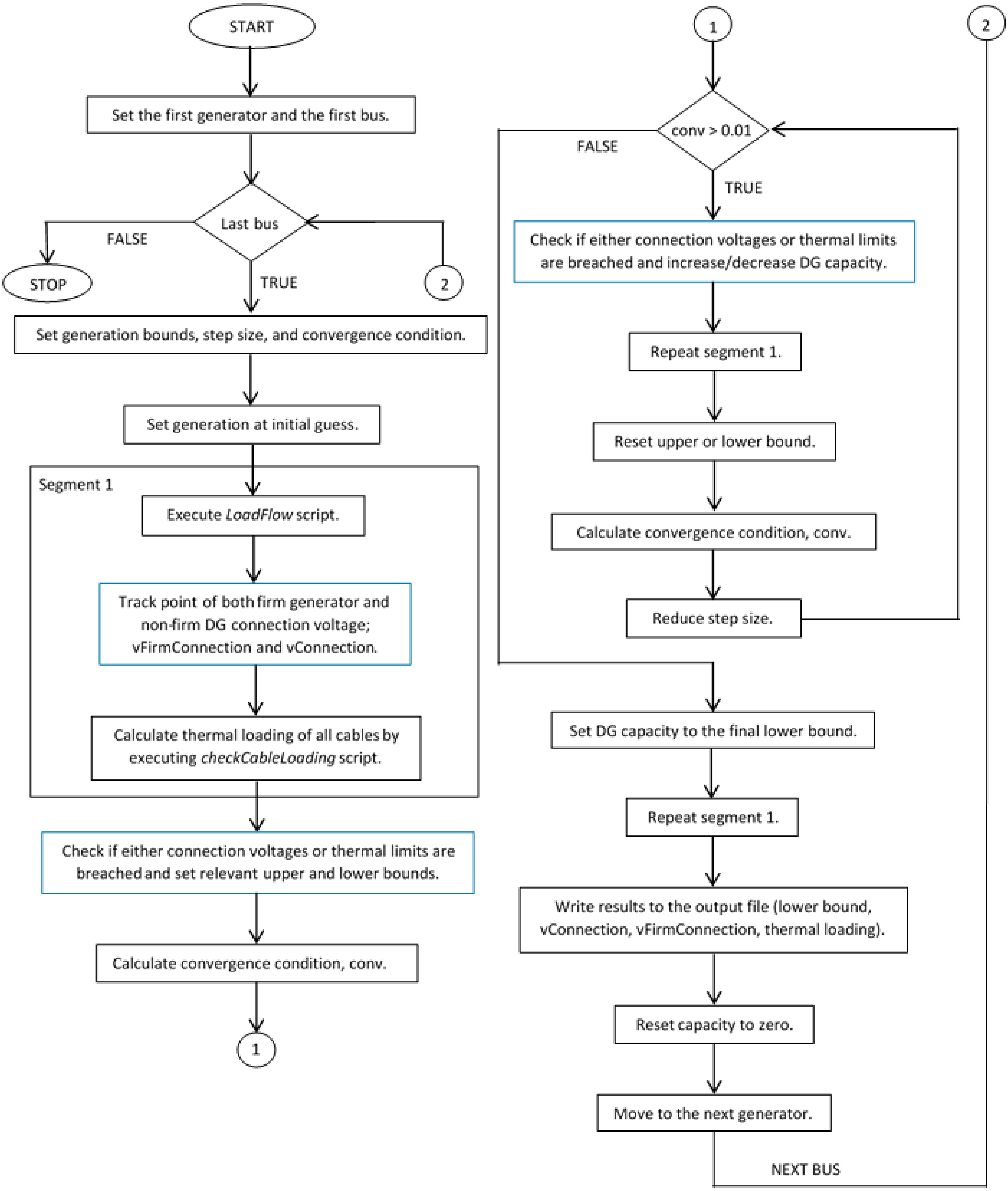



*Figure 36: The flow chart of the script DG_capacityWithMultipleGen*

### *A2.3 Study case: Different demand*

This study case uses a model described in Appendix A1.3 and developed scripts are explained below.

#### A2.3.1 Script: ThreePhaseTimeStepDiffDemand

The script is a modified version of the script *ThreePhaseTimeStep* shown in Figure 31. It is adjusted to calculate maximum DG capacity when demand is increased by 33.3kW on each phase at each secondary substation.

The script is the main script in this case study. The script opens two 'csv' input files. The first contains historical measurements of the primary voltage and historical demand readings at each secondary substation for three phase loads for Feeder 25 and the second contains the maximum DG capacity as calculated without demand response by the script *threePhaseTimeStep*. The script then sets the primary voltage and load values, the active and reactive power, to represent conditions at a particular time-step. The number of time-steps is equal to the number of days multiplied by 48, since we are using half hourly time-steps. Within the time-step loop, the script opens the second 'csv' file calls *LoadFlow* (shown in Figure 33), *checkCableLoading* (shown in Figure 34) and *newDGgen* scripts (see A2.3.2) to calculate the effect of demand increase to the maximum power injections at a particular bus. Finally, the script prints a number of completed time-step and closes input and output files.

The flowchart of the script is shown in Figure 37 with blue boxes presenting modifications of the script in Figure 31.

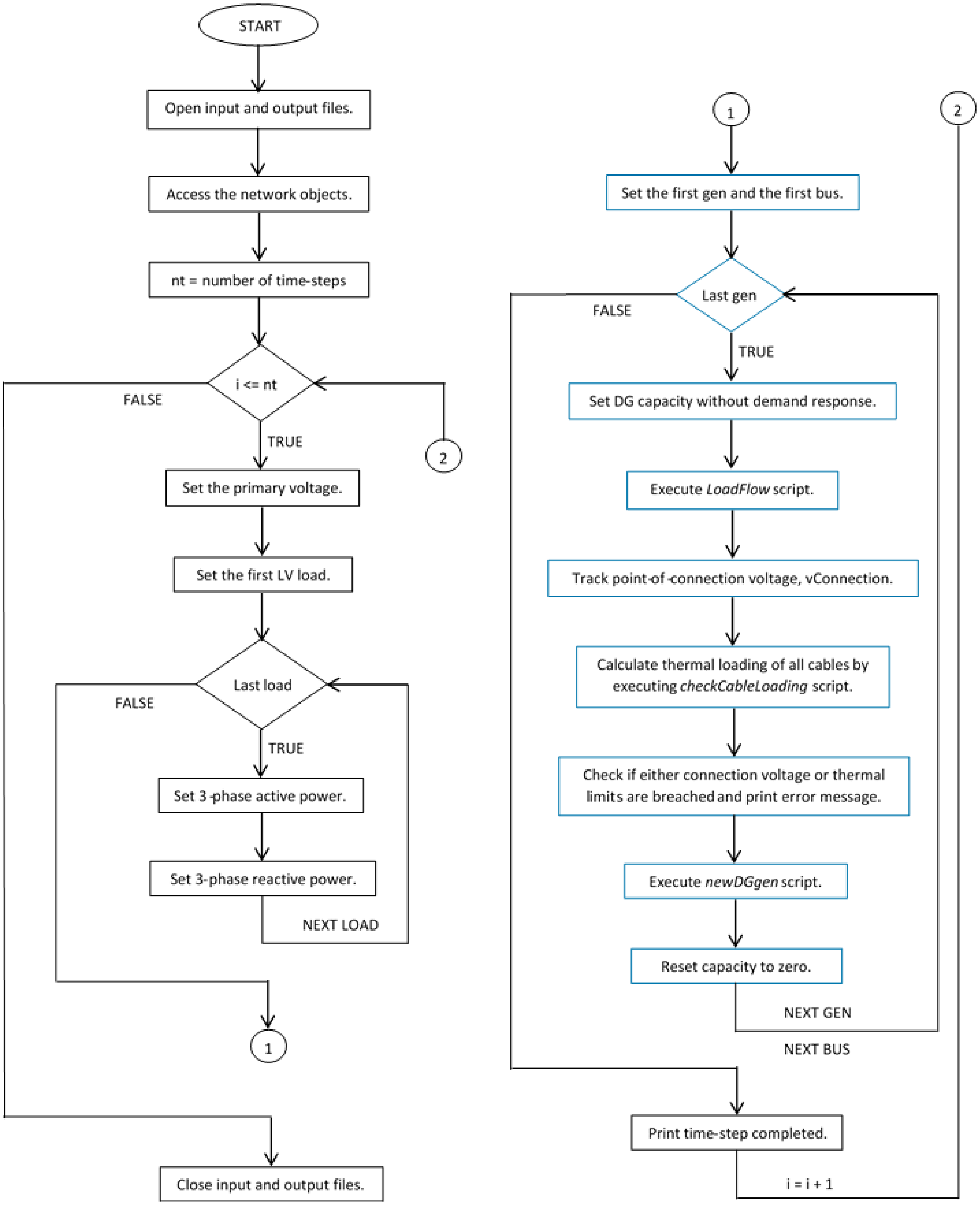



*Figure 37: The flow chart of the script ThreePhaseTimeStepDiffDemand*

### A2.3.2 Script: newDGgen

The script calculates the increase in network capacity created by additional demand elsewhere in distribution network. It maintains thermal limits across the feeder and checks voltage limits of non-firm DG connection point. The script loops around each load in order to find the maximum DG capacity that can connect at each secondary substation when the particular load is increased for 33.3kW per phase (100kW total load increase). Calculated capacity at each bus assumes NO DG connected at any other bus. While the local voltage limit is less than 11.25kV at the point of non-firm DG connection, and the thermal limit of all cables in the model is less than 100%, DG generation capacity is increased by 0.001MW. The load flow is calculated by executing the script *LoadFlow* shown in Figure 33 and the thermal loading of all cables by executing the script *checkCableLoading* shown in Figure 34.

Input parameters are: the set of all LV loads in the model; the maximum DG capacity as calculated without demand response; an object representation of wind generator; an object representation of secondary substation; the set of all cables in the model; an index of the output file in which the results will be written; and the load flow related to the active study case. The script returns the new maximum DG capacity and increase over the original demand level.

The flowchart of the script is shown in Figure 38.

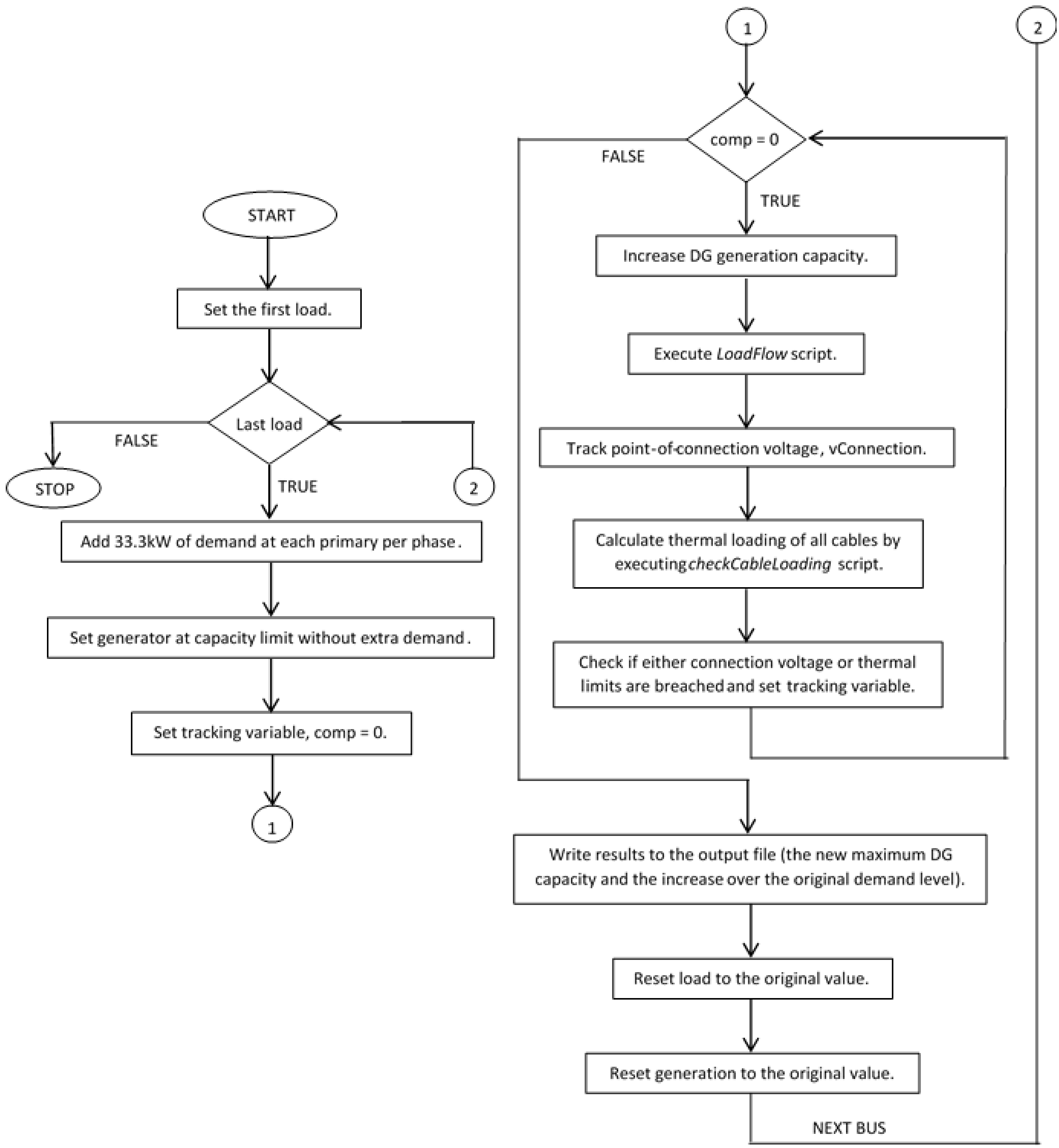



*Figure 38: The flow chart of the script newDGgen*

### *A2.4 Study case: HV voltage levels*

This study case uses a model described in the Appendix A1.3 and developed scripts are explained below.

#### A2.4.1 Script: HV voltage levels

The script is a modified version of the script *ThreePhaseTimeStep* shown in Figure 31. It is adjusted to calculate the voltage level at the end of a 33kV extension required to give the historically recorded 11kV primary voltage for the historically recorded demand conditions.

Before running it,the 'External Grid' should be edited in the Power Factory model by navigating to the Load Flow tab and ensuring that the 'setpoint' is set to 'bus target voltage'. Also, it should be ensured that the reference busbar is set to 'St. Andrews 186-25.

The script is the main script in this case study. The script opens a 'csv' input file with historical measurements of primary voltage and historical demand readings of three phase loads for each secondary substation on Feeder 25 with extra loads added to represent other feeders. It then sets the primary voltage and load values, the active and reactive power, to represent conditions at a particular time-step. The number of time-steps is equal to the number of days multiplied by 48, since we are using half hourly time-steps. At the end of each time-step, the script calculates the load flow by executing the script *LoadFlow* shown in Figure 33 and records the voltage level at the end of a 33kV extension.

The calculated 33kV voltages are stored in a 'csv' output file, and can be used as inputs to further studies which adjust the historically recorded conditions, for example by adding DG to the feeder.

The flowchart of the script is shown in Figure 39 with blue boxes presenting modifications of the script in Figure 31.

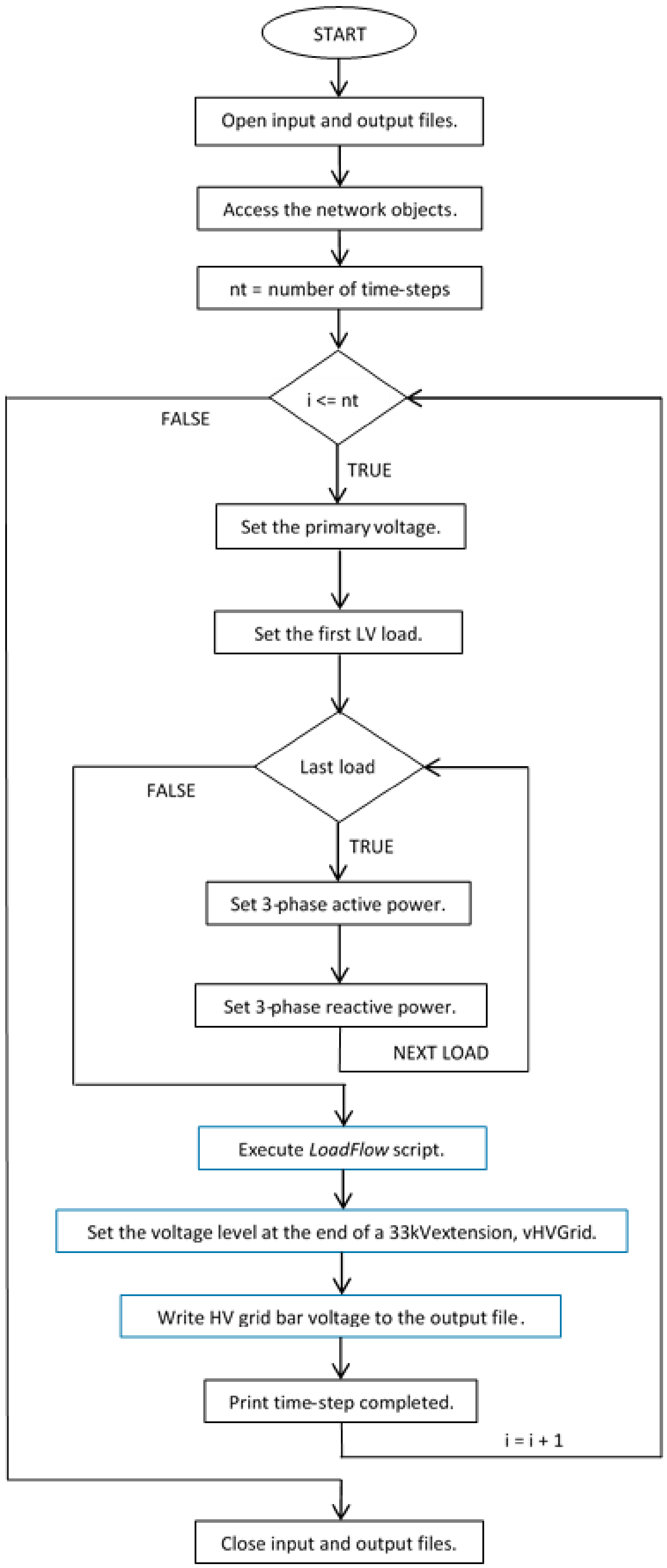



*Figure 39: The flow chart of the script HV_voltage_levels*

# Appendix 3: Modelling specification, April – July 2014

Strathclyde will undertake a number of modelling activities over the period April – July 2014 as part of its role in the Accelerating Renewable Connections (ARC) project with Scottish Power Energy Networks (SPEN). This work will develop understanding within the wider ARC team of issues related to voltage constraints on the 11kV network, and limitations imposed on distributed generators connecting at this level. The work will focus on general understanding, and the development of general techniques rather than focusing on specific cases.

## Summary

The work will make use of the data collected as part of Strathclyde's previous work: WP5.2, milestone 'Collation of data from ARC case studies to produce data sets for evaluation'. Data collected and to be used in this modelling is as follows:

1. Detailed monitoring data for 11kV feeder from St. Andrews area collected as part of the Flexible Networks project.
2. Historic measurements of output for Dunbar connected wind farms.

The work will fulfil Strathclyde's milestone under WP5.2 'Production of evaluation models of ARC case studies and smart solutions' to be delivered by 31st July 2014.

Strathclyde will liaise with SPEN and Smarter Grid Solutions (SGS) throughout to exchange models and results with when appropriate.

## Outcomes

Strathclyde will produce the following:

- A short technical report detailing the set-up and outcomes of each of the modelling tasks.
- Full modelling results provided in a suitable format (excel spreadsheet or csv files).
- A half-day workshop to present and discuss the results with the wider ARC team.

The time-scale for this work is 3.5 months with completion on 31st July 2014.

## Modelling tasks

| **Task 1:** | **Set up model of single 11kV feeder based on St. Andrews data** |
|---|---|
| **Activities** | 1. Load and verify Power Factory model of feeder as supplied by SPEN.<br>2. Adjust model tap-settings for secondary transformers based on information provided by SPEN.<br>3. Ensure historical measurements of power flows and voltage etc. can be reproduced using the models. |
| **Additional Information required** | - Tap-settings for secondary substations.<br>- Measurements of voltage at primary substations. |
| **Outcomes:** | i. Operational model of feeder verified against monitoring data.<br>ii. Internal documentation capturing Strathclyde's understanding of the feeder. |

| **Task 2:** | **Business-as-usual design specifications: static** |
|---|---|
| **Activities** | 1. Connecting a single generator: |

| | |
|---|---|
| | - Model the connection of a single distributed generator to a secondary substation.<br>- Constrain power factor to region 0.95-1.05.<br>- Find the maximum capacity of generation, for the full range of demand conditions that keeps voltage less than 11.25V.<br>- Document voltage levels across the rest of the feeder.<br>- Repeat for different secondary substations.<br>2. Connecting multiple generators:<br>- Model the connection of two or more distributed generators to different secondary substations.<br>- Investigate the effect of varying capacities at each generator on maximum capacities achieved whilst maintaining the 11.25kV limit on both under varying demand conditions.<br>- Document the effect of these scenarios on voltage levels across the feeder. |
| **Additional Information required** | - Outcomes of Task 1<br>- Discussion with SGS regarding data formats and scripting of simulations |
| **Outcomes:** | i. Confirmation of the ability of the existing design standards to maintain voltage levels across the feeder with one or more distributed generators operating with terminal voltage below 11.25kV.<br>ii. Greater understanding of the interaction between demand, distributed generation and voltage along a single feeder.<br>iii. Identify potential for relaxing the 11.25kV limit. |

| **Task 3:** | **Relationship between Power injection and voltage** |
|---|---|
| **Activities** | 1. Single generator: For 3 secondary substations. Find the relationship between power injection and voltage where voltage is in the region 11.2kV– 11.3kV.<br>2. Multiple generator: Connect generators at 2 of the secondary substations used in Task 3.1. Investigate the effect of varying power injection at 1 on its local voltage whilst keeping the second generator constant. |
| **Additional Information required** | - Output of Task 2. |
| **Outcomes:** | i. Understanding of the sensitivity of voltage to power injection from distributed generation along the 11kV feeder<br>ii. Sensitivity values in kV/kW for scenarios studied; understand if sensitivities are constant across the terminal voltage range 11.2 – 11.3kV.<br>iii. Recommendation for focusing further studies in this area |

| **Task 4:** | **Active Management a single generator on a single feeder** |
|---|---|
| **Activities** | 1. Define scenario with Distributed Generation capacity connected to a secondary substation which has the potential to exceed 11.25kV under some demand conditions.<br>2. Scale Dunbar wind farm data to represent suitably sized community wind farm of capacity chosen in Task 4.1.<br>3. Carry out time-series analysis, curtailing generation when required to |

| | |
|---|---|
| | maintain the 11.25kV limit.<br>4. Repeat with relaxed voltage constraint informed by outcome (iii) from Task 2. |
| **Additional Information required** | - Outcome of task 2<br>- Possibly using scripting tools developed by SGS |
| **Outcomes:** | i. Developed methodology (incorporating learning from SGS) for curtailment studies based on static voltage levels<br>ii. Identify the potential effectiveness and viability of relaxing the 11.25kV voltage constraint |

| **Task 5:** | **Voltage constraints with multiple feeders** |
|---|---|
| **Activities** | 1. Set up model of primary substation with two 11kV feeders based on information from St. Andrews Flexible Networks project.<br>2. Connect single generator on each feeder.<br>3. Investigate voltage across both feeders for low and high demand scenarios and combination of high-high and high-low / low-high output from the two generators |
| **Additional Information required** | - Suitable two feeder network model |
| **Outcomes:** | i. Characterisation of voltage levels across multiple-feeders due to generation and demand variations across those feeders.<br>ii. Identify situations in which the learning from Tasks 2 – 4 are applicable to multiple feeders and situations where further work is required in respect of multiple feeders set ups<br>iii. Recommendations for future investigation of voltage management in multiple feeder scenarios |

## Future Work

It is expected that the outcomes of the modelling tasks detailed here will form the basis for the further development of ANM based management of 11kV voltage constraints

- Interaction between 11kV voltage constraints and wider (33kV and GSP based) thermal constraints.
- The need to develop smart tap-changing at primary substations as part of 11kV voltage management.
- The need to investigate under voltage effects on the Low Voltage network if changes are implemented to design standards for voltage levels at primary substations.
- Application of learning to case-studies in the ARC area.