PV Generation Hosting Capacity in Dominican Distribution Grids – Final Report

Permissible PV Penetration Level in the Dominican Distribution Grids

GOBIERNO DE LA
REPÚBLICA DOMINICANA
ENERGÍA Y MINAS

Proyecto
Transición
Energética

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LIST OF ABBREVIATIONS

CCE	Centro de Control de Energía
CPUC	Californian Public Utilities Commission
DSO	Distribution System Operator
FERC	Federal Energy Regulatory Commission, United States
GIS	Geographic Information System
HV	High Voltage
HVRT	High Voltage Ride-Through
LFSM-O	Limited Frequency Sensitive Mode – Overfrequency
LFSM-U	Limited Frequency Sensitive Mode – Underfrequency
LV	Low Voltage
LVRT	Low Voltage Ride-Through
MV	Medium Voltage
NREL	National Renewable Energy Laboratory, United States
OC	Organismo Coordinador del SENI
RE	Renewable Energy
SENI	Sistema Eléctrico Nacional Interconectado
SIE	Superintendencia de Electricidad
TSO	Transmission System Operator
VRE	Variable Renewable Energy

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EXECUTIVE RESUME

The Dominican Republic benefits from a high abundance of solar insulation, providing good potential for distributed solar photovoltaic (PV) generation in the country. A net metering scheme, introduced in 2012, provides incentives for grid users to build PV installations on rooftops of households and small commercial buildings as well as free-field PV plants.

However, high PV penetration levels can have detrimental effects on the distribution grids requiring network upgrades to accommodate higher PV shares. A balance must therefore be found between promoting the growth of PV, on the one hand, and minimizing the impact on electricity networks, on the other hand, to ensure both the transition to a cleaner and sustainable electricity mix and the provision of cheap and reliable electricity supply.

For this matter, this study analyses the maximum PV penetration levels on a number of representative, real distribution feeders in the Dominican Republic and provides recommendations to improve the current regulatory landscape for distributed generation.

Technical and regulatory requirements currently applicable for PV system installations connecting to the distribution grid are analysed and a first high-level review conducted, with recommendations based on international good practices. The most important recommendations include adding an LFSM-O (also called frequency-watt) requirement to avoid many PV systems disconnecting simultaneously, requiring reactive power capability and control modes from PV systems as well as other technical requirements on inverter-based generators.

A major limiting factor for distributed PV growth is identified in the current regulatory limit of restricting the maximum PV penetration within a distribution feeder to 15% of the feeder's peak demand, above which small units that wish to connect are required to pay for a supplementary study. This regulatory limit is very strict and severely reduces penetration levels below the technically justified level, as well as adds a significant burden on the EDE's side to perform a supplementary study for each PV application above such limit.

Therefore, a simulation study is conducted on 12 representative distribution feeders to establish actual maximum penetration levels based on technical analysis and by looking at typical issues in distribution grids due to the impact of PV. The 12 distribution feeders are selected from all Dominican feeders, looking at feeders with typical as well as extreme characteristics. The medium voltage feeders were imported from the respective tool of the EDE into the power system simulation software DIgSILENT PowerFactory.

All 12 distribution feeders are analysed with respect to two operational situations, during maximum demand without PV generation and during minimum demand with full PV generation output. Two PV scenarios are investigated, with a homogeneous PV distribution according to distribution transformer sizes ("uniform PV") and one with the majority of PV generation located at the end of the distribution feeder ("uneven PV"). In the subsequent simulations the PV capacity is gradually increased up to a level of 150% of peak demand in order to determine the PV penetration level above which impermissible conditions for grid operation appear.

Through the simulations it is determined that for most feeders overvoltage problems are the more restricting factor compared to other PV impacts. The issue of overvoltages due to reverse power flows is illustrated in Figure 1.

The results from the simulations are depicted in Figure 2. They show that most feeders have a much higher PV penetration level than the currently enforced limit to 15% of peak load. Urban feeders are generally able to accommodate a very high PV penetration level, with the worst example analysed having a penetration level of 75% for an uneven PV distribution. For rural feeders, penetration levels are generally much lower but in most cases still much higher than the 15% limit. Only one feeder shows an actual penetration level of only 20% for an uneven PV distribution.

Figure 1: Illustration of Maximum and minimum voltage during peak demand and peak generation. Example on a rural feeder with ± 10 % voltage range.

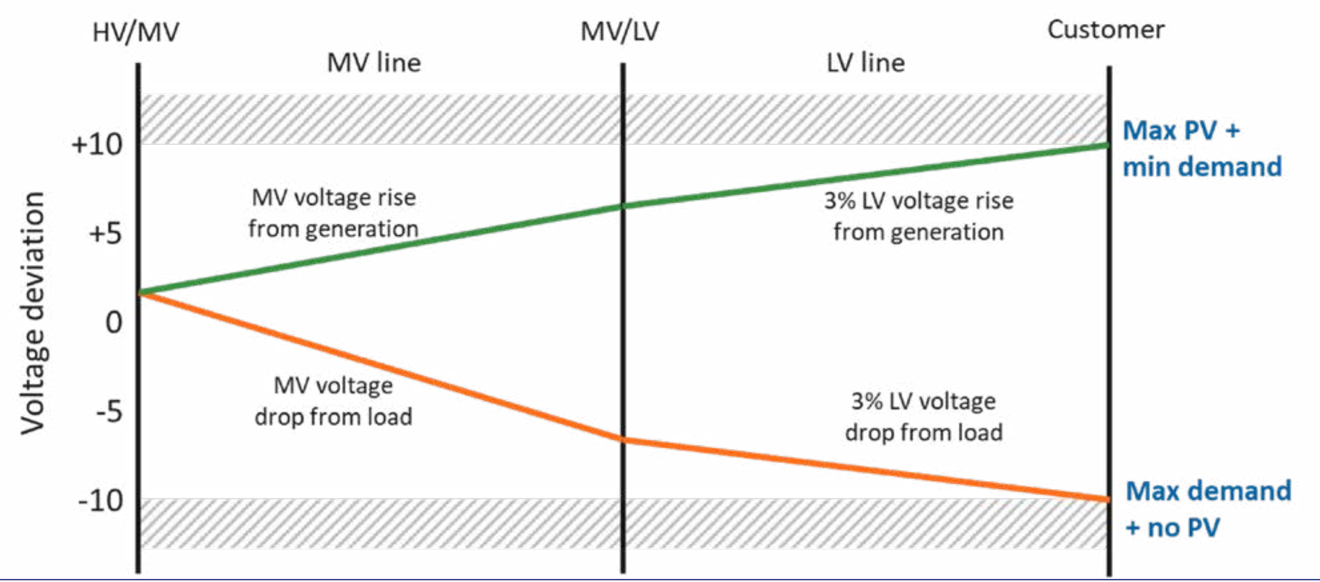
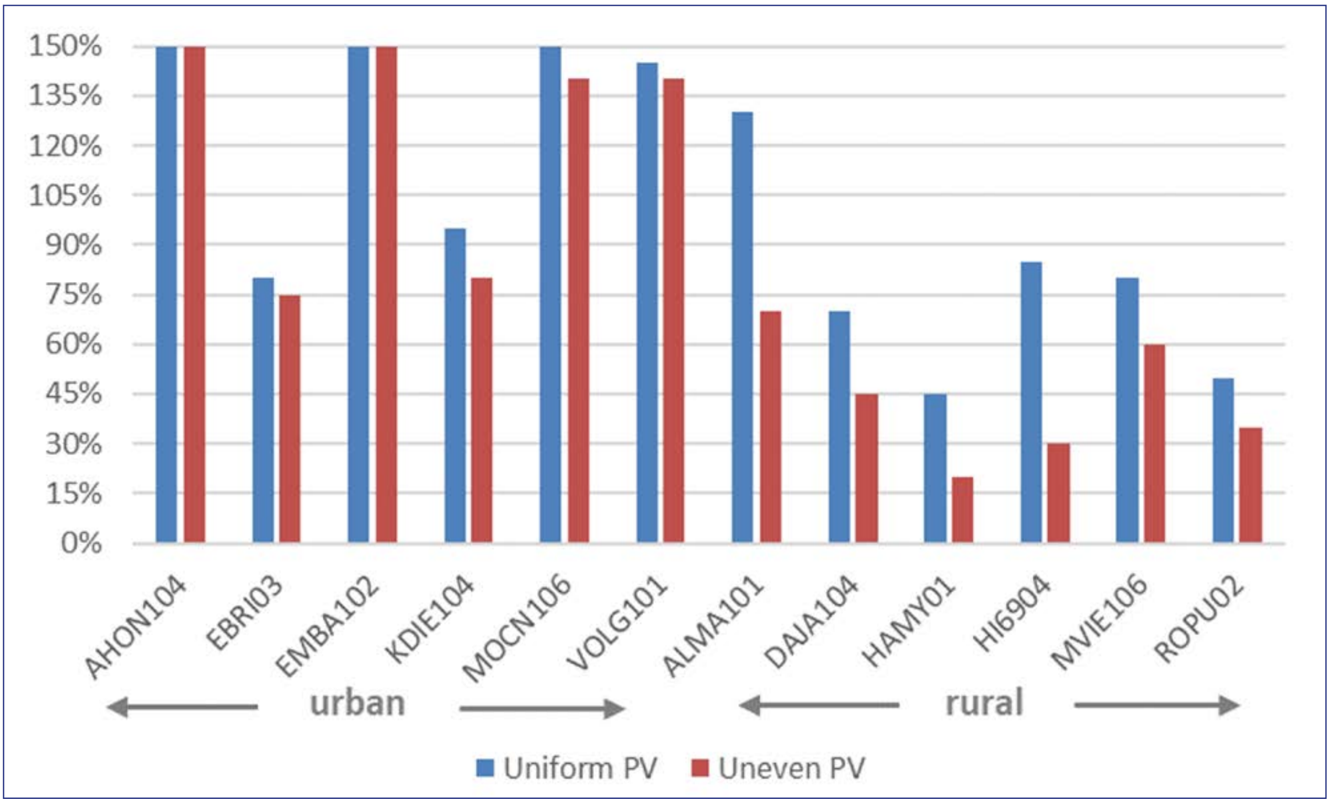
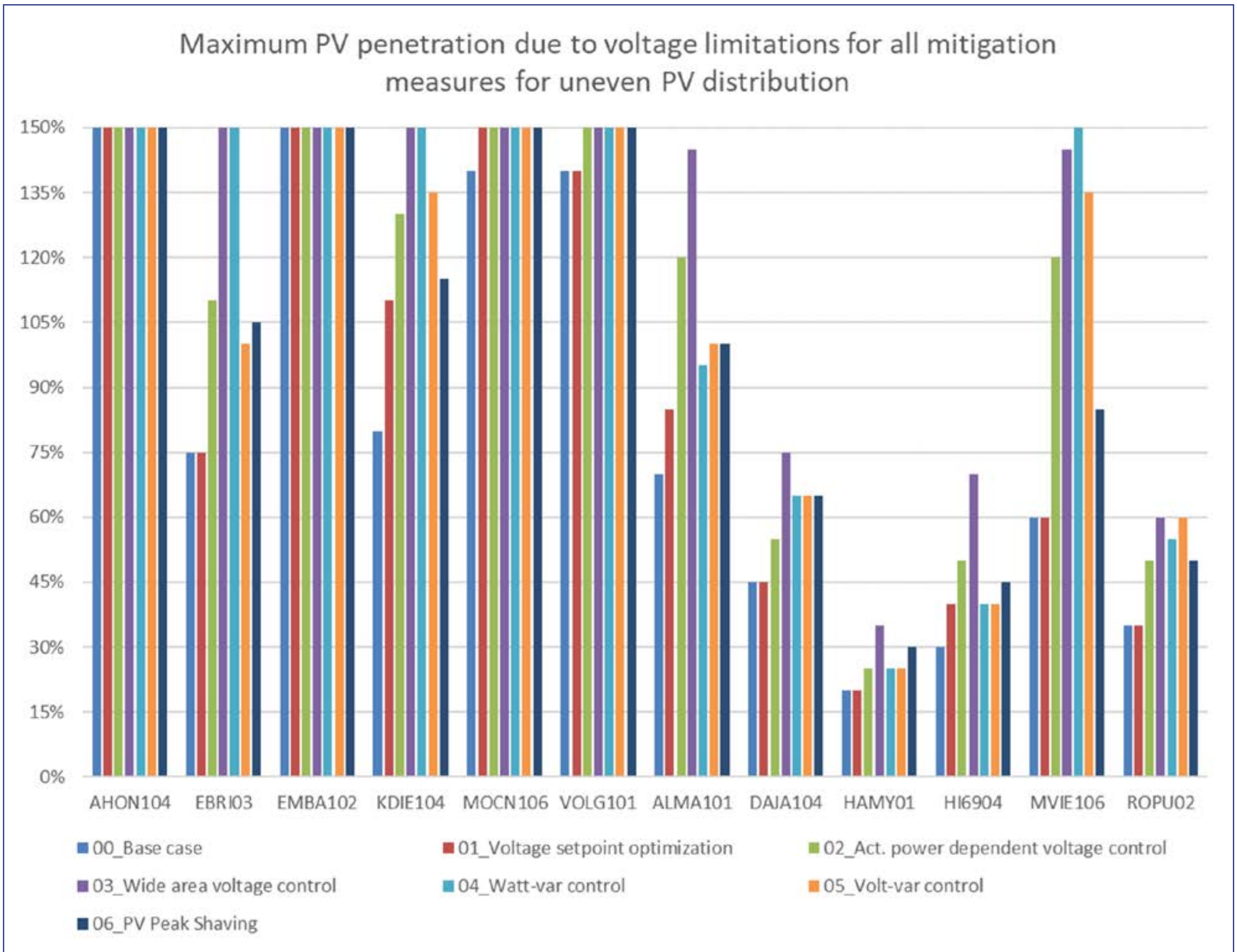


Figure 2: Maximum PV penetration levels of the 12 distribution feeders for uniform distribution of PV and a distribution at the end of the PV



Subsequently, mitigation measures are analysed that can in most cases further increase the feeder's hosting capacity for PV, sometimes significantly. Figure 3 shows the results for an uneven PV distribution and considering voltage violations.

Figure 3: Comparison of maximum PV penetration levels for all mitigation measures, considering voltage violations and a PV distribution at the end



Of these mitigation measures, the study identifies the following ones as the ones with the best cost-benefit ratio as their implementation comes at almost no cost:

- active power-dependent voltage control at the HV/MV transformer,
- utilizing reactive power control from PV inverters, and
- PV peak shaving through a PV generation cap at 70% or 80% of installed PV panel capacity by limiting the inverter size.

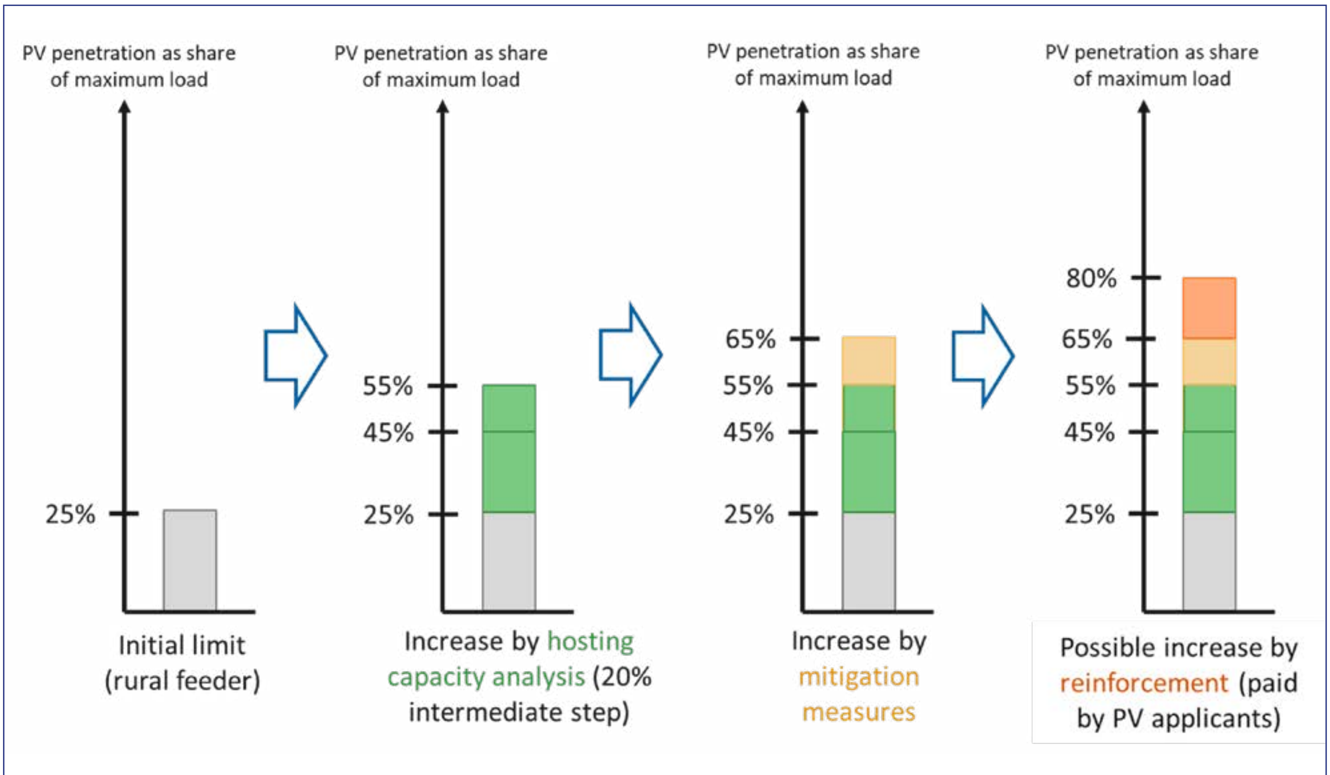
With the implementation of such measures, even in the most unfavourable situation a penetration level of at least 25% of peak demand is achievable.

Concluding, the study suggests that better measures should be implemented to achieve a more dynamic assessment of a feeder's maximum PV penetration level as opposed to a fixed regulatory limit.

This was addressed in the final chapter, providing recommendations on the current interconnection processes and suggesting that the current 15% limit should be increased to 50% for urban feeders and 25% for rural feeders. After breaching this threshold, a technical analysis ("hosting capacity study") should be conducted to determine the new limit. Only if the hosting capacity study does not result in a further increase of PV penetration levels and the above mentioned mitigation measures have been implemented, should PV projects be deterred from interconnecting. A further study should then be carried out to determine the cost for any distribution network upgrades to increase the PV hosting capacity. The cost of the necessary distribution network upgrades should be communicated to the applicants and split among all willing applicants in order to allow for a fairer distribution of costs and achieve higher PV penetration levels.

An illustration of the required steps for hosting capacity analysis is provided in Figure 4. Detailed depictions of the interconnection and hosting capacity process are presented in Figure 62 and Figure 63 of chapter 12.8.

Figure 4: Illustration of hosting capacity measures, including mitigation measures and network reinforcement



Further recommendations are provided regarding specifics of the interconnection process concerning deadlines, a new screen for 3% of maximum voltage deviation in the LV network additional to the deviations taking place in the MV network, cost recovery options for the hosting capacity studies, and publication of hosting capacity studies. Technical requirements, already discussed in chapter 2.2, are recommended to be implemented through an adoption of the IEEE 1547-2018 standard or equivalent standards. Alternatives to handle maximum PV penetration levels and grid reinforcement from a regulatory perspective are pointed out as well.

All recommendations can be easily understood and traced by going through the green coloured tables in chapter 12.

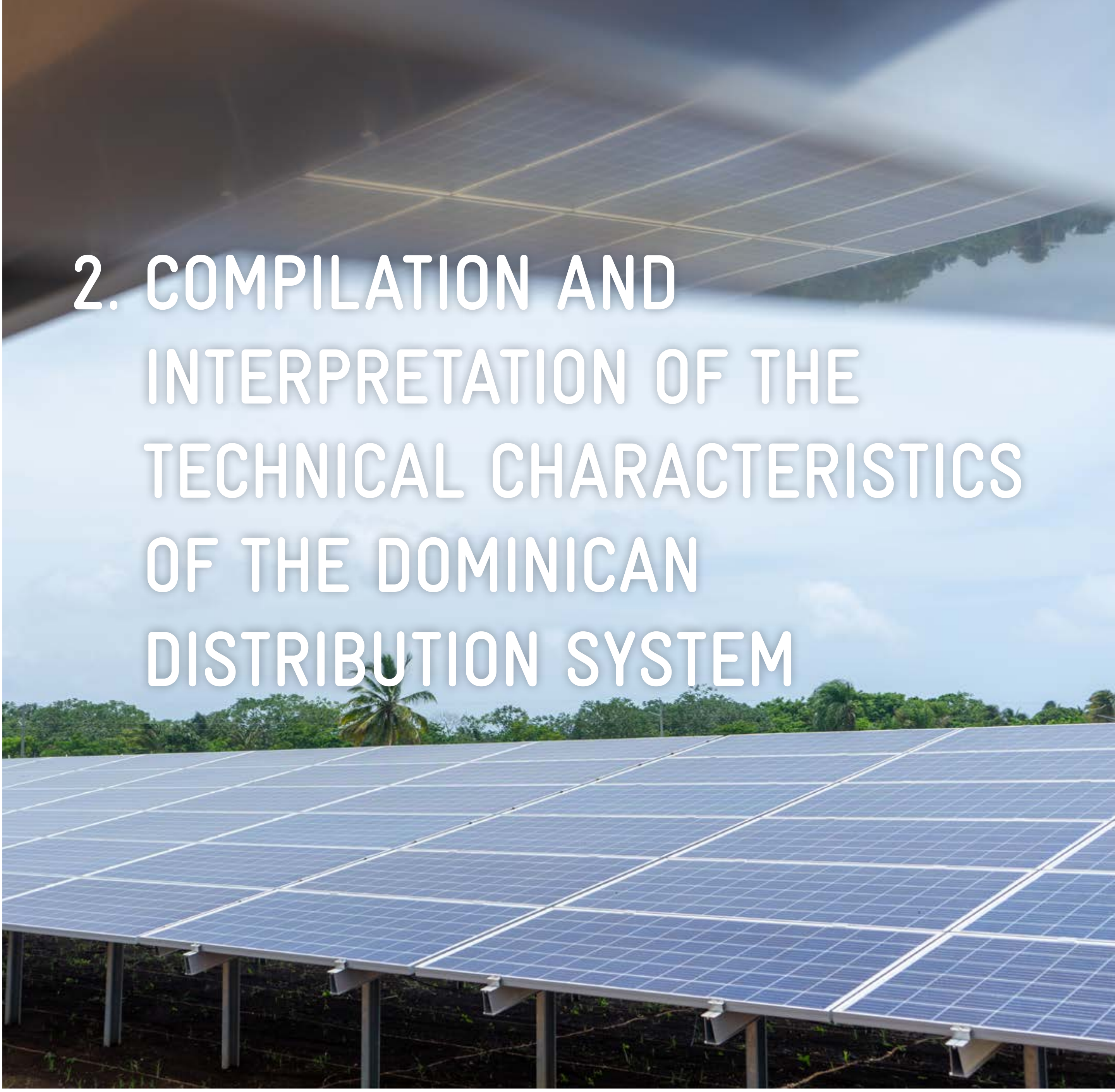
1. INTRODUCTION

The following document is the final report of the study on 'Permissible PV penetration level in the Dominican distribution grids' and supported by GIZ and the Dominican Ministry of Energy and Mines.

The document encompasses the following chapters:

- Chapter 2: Technical characteristics of the Dominican distribution system
- Chapter 3: Limiting factors for the penetration of distributed photovoltaic energy
- Chapter 4: Selection process of MV feeders
- Chapter 5: Simulation methodology to determine the maximum PV penetration limits in the MV feeders
- Chapter 6: Model setup of the investigated feeders
- Chapter 7: Detailed simulation results on PV hosting capacity on the example of three feeders
- Chapter 8: Consolidated simulation results encompassing all feeders
- Chapter 9: Simulation results on mitigation measures to increase PV hosting capacity
- Chapter 10: Investigation of protection issues
- Chapter 11: Conclusions and technical recommendations
- Chapter 12: Recommendations to improve the current interconnection process

2. COMPILATION AND INTERPRETATION OF THE TECHNICAL CHARACTERISTICS OF THE DOMINICAN DISTRIBUTION SYSTEM



2.1 REVISION OF TECHNICAL PARAMETERS IN THE REGULATION RELATED TO RE INTEGRATION IN THE DISTRIBUTION LEVEL

This project will focus on the distribution system level of the Dominican Republic, and therefore, on medium and low voltage levels, the former corresponding mainly to nominal line-to-line voltages of between 4.16kV and 34.5kV and the latter corresponding mainly to voltages of 208V, 220V, 120/240V and 480V. For this task, the following relevant documents were reviewed:

- The General Electricity Law (number 125-01 of 2001) and its application regulations (*Ley General de Electricidad No. 125-01 y su Reglamento de Aplicación*), in the following referred to as **General Electricity Law**;
- Law on the Incentive to the Development of Renewable Sources of Energy and its Special Regimes (number 57-07 of 2007) and its application regulations (Ley número 57-07 *Sobre Incentivo al Desarrollo de Fuentes Renovables de Energía y sus Regímenes Especiales*), in the following referred to as **RE Incentive Law**;

- Complementary procedure for integration and operation of special regime generation plants in the national interconnected system (2011) (*Procedimiento complementario para la integración y operación de las centrales de generación de régimen especial en el SISTEMA ELÉCTRICO NACIONAL INTERCONECTADO (SENI)*), in the following referred to as **Complementary INGERE Regulations**;

- Distributed Generation Regulations (2012) (**Reglamento Interconexión Generación Distribuida**), in the following referred to as **Distributed Generation Regulations**;

- Net Metering Regulations (2012) (*Reglamento Medición Neta*), in the following referred to as **Net Metering Regulations**;

- Draft regulation (not in force) for the approval and operation of distributed generation facilities from renewable energy sources connected to the MV or LV (Draft version 01, December 2019) (*Reglamento para la aprobacion y operación de instalaciones de generacion distribuida a partir de fuentes renovables de energia*), in the following referred to as **2019 Draft Distributed Generation Regulations**.

These documents govern connections of RE facilities to the Dominican Distribution Grid. Further documents were also consulted to complement the above-listed documents[1].

The objective of this task is to review these documents and compared to relevant international examples. From the comparison, high level recommendations are generated, which will serve as a basis for discussion with GIZ and relevant stakeholders (distribution system operators, the regulator, etc).

2.2 ANALYSIS OF TECHNICAL PARAMETERS OF RE INTERCONNECTION TO THE DOMINICAN REPUBLIC DISTRIBUTION SYSTEM, COMPARISON TO INTERNATIONAL BEST PRACTICES AND RECOMMENDATIONS

For this task, the Dominican Republic current regulations will be compared to regulations of Germany, Ireland and Barbados. Germany was selected due to having longer experience with connecting decentralised PV systems to their grid, high PV penetration as well as having established and internationally recognised good practices. Ireland and Barbados were selected due to their characteristic of island system as well as good practices. Ireland is weakly interconnected island system, only few GW of installed capacity (approximately 2-3 times as large as the Dominican Republic) and a DSO with much tighter control on distributed generation compared to other unbundled systems. Barbados represents a small island system in a Caribbean country, vertically integrated and interested in harmonizing grid codes in the Caribbean region. When relevant, key examples from other countries other than the above-listed will also be provided.

The high-level comparison will be made structured in seven (7) main topics: Frequency control, voltage control, fault behaviour, controllability/forecasting, connection process, compliance and metering. These will be analysed next. For each topic analysed, the regulations in force are considered and a comment regarding the Draft Distributed Generation Regulations of 2019 is added when changes are identified from the current regulations.

1 Further documents consulted to complement the analysis included: Procedimiento Certificación Sistemas Fotovoltaicos (2015); Resolución SIE-029-2015-MEMI; Resolución SIE-030-2015-MEMI; Resolución SIE-056-2016-MEMI (Article 690); Consulta sobre el cálculo del factor de potencia en clientes con Medición Neta (Consulta EdeEste y respuesta SIE, 2017).

2.2.1 Frequency-Related

2.2.1.1 Frequency Operating Range

Current Provisions	As per Article 150 of the General Electricity Law, the nominal frequency in alternate electric current systems will be 60 Hz. Technical conditions to regulate the frequency must be such that the frequency remains within the range of: a) 59.85 to 60.15 Hz for 99.0% of the time b) 59.75 at 60.25 Hz for 99.8% of the time Furthermore, in the Distributed Generation Regulations, it states that in the event of variations in frequency, the Generation System will be disconnected considering: Frequency / Disconnection Time (s) F > 60.5/ 0.16 s 57.7 < f < 59.2/ Adjustable (0.16 -300 s) F < 57.7/ 0.16 s
International Experience	International good practice is to specify unlimited operation of generators within a relatively narrow frequency range and time-limited operation within a wider frequency range. The requirement of longer operating durations in wider frequency bands significantly increases system security by avoiding disconnection of potentially large amounts of rooftop solar PV capacity at the same time during disturbances. In Germany, too tight thresholds had been required at first, later requiring expensive retrofitting schemes (the issues became known as the **"50.2 Hertz problem"** and the "49.5 Hertz problem"). Rooftop PV units in Germany were originally required to disconnect immediately if the frequency exceeded 50.2 Hz. This requirement was set when PV shares were small in the system and, in case of a problem, these should disconnect and leave the problem to the more controllable conventional power plants. However, the German rooftop PV incentive scheme proved to be so successful that installed PV capacity soon crossed the threshold of 3000 MW, which is the amount of FCR (primary reserves) always available in the central European synchronous area. An event with a frequency exceeding 50.2 Hz on a sunny day would lead to the loss of all that generating capacity and thus a severe underfrequency event that the FCR may not be able to cope with. With PV capacity rising further (currently above 40GW), the requirement was changed and a costly retrofitting scheme was introduced with the cost borne by the grid operators. The German LFSM-O requirement appeared first in the German transmission codes and was applied to VRE only, but was then also added to all other codes in the wake of the 50.2 Hz issue.
Recommendation	The Distributed Generation Regulations already specify unlimited and time-limited operation ranges. However, it is strongly recommended to include a LFSM-O requirement for PV system inverters for frequencies above 60.5Hz to avoid many PV units disconnecting simultaneously and aggravating the issue (see LFSM-O requirement recommendation in the next table).

2.2.1.2 Response to Frequency Deviations and Active Power Control

Current Provisions	In Article 123 of the RE Incentive Law application for regulation, it states that Special Regime generators may provide services of primary and secondary reserve, however, they are not obliged to participate in frequency regulation.
International Experience	Recommended Requirements: 1. At least for larger plants (size to be specified), allow adjustment of power output under the command of the System Operator. In Germany, this is already applicable for RE plants connected at the LV level (for sizes above 30kW for PV and conventional generators, and 100kW for other RE). For VRE units, this adjustment is in accordance with the variation of the primary energy source. The power generator facility may only return to free generating mode when power control mode is lifted by the distribution operator. 2. For all plants, be capable of Active Power Reduction with increasing frequency (LFSM-O) 3. For all plants (that are already curtailed) be capable of an active power increase with decreasing frequency (LFSM-U) 4. Active Power Gradient Limitations Large VRE generator facilities implementing power control mode must be equipped to receive correspon-ding target values from the distribution operator. Requiring active power controllability from generators even at the low voltage level is common interna-tional practice. For example, it has been required in Germany and Denmark for several years already. The conditional exemption for units below 30 kW (can implement a permanent cap if dynamic curtailment is not desired) is modelled on the German example.
Recommendation	Direct requirements on the frequency response methods for non-dispatchable INGERE (includes PV plants) were not found. It is strongly recommended to introduce the international good practices listed, especially LFSM-O requi-rements for all PV systems and LFSM-U only for those which are already curtailed. Most PV systems are already capable of operating in LFSM mode, therefore this would lead to no additional costs. No interven-tion is needed from the DSO during the operation of the system in this mode.

2.2.2 Voltage-Related

2.2.2.1 Voltage Operating Range

Current Provisions	According to article 149 of the General Law, SENI's operation must maintain the resulting voltage levels, in the different substations, within a range of plus or minus five percent (±5%) around the nominal vol-tage. Voltage variations in the Distribution Network shall be within a range of plus or minus seven point five percent (± 7.5%) of the nominal voltage in urban areas and plus or minus ten percent (± 10%) in rural areas, except in the case of fortuitous event or Force Majeure. The Distributed Generation Regulations state that, in the event of variations in the magnitude of the electrical service voltage at the Common Connection Point, the equipment will be disconnected from the Electric Distribution System as below: Voltage Range (% of Nominal Voltage) / Disconnect Time (s): V < 50/ 0.16 s 50 < V < 88/ 0.2 s 110 < V < 120/ 1 s V > 120/ 0.16 s
International Experience	Unlimited operation of generators within a voltage range slightly larger than normal operational range, time-limited operation within a wider voltage range.
Recommendation	The Distributed Generation Regulations already specify unlimited and time-limited operation ranges. The disconnection times listed are recommended to be adjusted considering a voltage ride through capability. This capability is recommended in section 2.2.3.1.

2.2.2.2 Reactive Power Ranges and Control Modes

Current Provisions	The Distributed Generation Regulations state on page 63 that the Generation System will not regulate the voltage at the Common Point of Connection to the Electric Distribution System. Furthermore, article 124 of the RE Incentive Law defines voltage control requirements (reactive power requirements) for wind and solar plants, however, for solar PV plants, requirements are only defined for those connected to high voltage level[2]. The Distributed Generation Regulations state that the operating power factor of RE generators inter-connected to distribution networks must not exceed the limits established in the reactive remuneration regulation that the SIE will issue.
2019 Draft Proposal	Every installation with distributed generation must maintain a minimum power factor of 0.9 both in its consumption and in its generation in such a way that it does not disturb the stability of the system.
International Experience	Specification of minimum requirements for reactive power makes sense to make the situation more predictable for distribution operators. It is common good practice to demand generators connected to the medium and low voltage distribution grid the capability of operating at least at off-unity power factor. PV plants are recommended to be capable of operating in the modes: 1. fixed power factor and 2. At least one active power based and one voltage-based characteristic: A) cosϕ(U) or cosϕ(P) (recommended for connection level of 10 kV and below) B) Q(U) or Q(P) (recommended for connection level above 10 kV). In Germany, all generators connected to the LV level are required to be able to realize fixed cos ϕ as well as a cos ϕ(P) characteristic. Generators above 4.6 kVA are also required to be capable of Q(U) operation.
Recommendation	Clearly specify reactive power and voltage control for generators. Specify minimum required reactive power range for all generators (as per Draft 2019). For the low voltage, a cos phi range is recommended, for medium voltage, a Q(P) or Q(U) range is recommended. While the regulations should require the capability of PV systems to operate in several of the control modes, the decision of which mode to activate in each generator is left to the DSO. This is aligned with German good practices.

2 Project stakeholders have indicated that there is a mistake in the 57-07 regulations. Subparagraphs b of paragraphs 1 and 2 of Article 124 were in fact repealed by Decree 646-2011 dated October 21, 2011.

2.2.3 Fault behaviour

2.2.3.1 Voltage Ride Through

Current Provisions	The Distributed Generation Regulations state that in the facilities of 3 phase Renewable Generation Systems, the Protection Equipment will disconnect the Generation System against fluctuations in the current or voltage of any phase in compliance with the recommendations of the operational and protection requirements of the IEEE 1547 Standard. This includes that the equipment will resist over current and over voltage according to IEEE C62.41.2-2002 or IEEE C37.90.1-2002 standards. The equipment will withstand 220 percent of the nominal interconnection voltage when energized. Furthermore, as listed before, in the event of variations in the magnitude of the electrical service voltage at the Common Connection Point, the equipment will be disconnected from the Electric Distribution System as below: Voltage Range (% of Nominal Voltage) / Disconnect Time (s): V < 50/ 0.16 s 50 < V < 88/ 0.2 s 110 < V < 120/ 1 s V > 120/ 0.16 s
International Experience	Recommended Capabilities according to German good practices: 1. Low Voltage Ride Through (LVRT) and High Voltage Ride Through (HVRT). The code should provide exact descriptions of conditions when generators must remain connected to the grid after the initial voltage dip or rise associated with different types of faults. Whereas common requirements for MV level, HVRT and LVRT have been added to the LV level in Germany only recently (in 2018). MV and LV envelopes differ, with MV envelope being stricter. 2. During voltage disturbances, VRE generator facilities below a certain size or voltage level (typically those connected to the LV) must not generate any current, while remaining connected to the distribution grid. This is due to high grid impedance and potentially harmful interaction with grid protection (fault detection). As for PV units connected to the MV, these are often required to inject or consume reactive and/or active current with a magnitude proportional to the voltage variation with respect to the normal operating voltage.
Recommendation	Introduce clear voltage ride-through and reactive voltage support during voltage ride through requirements based in the Dominican Republic system characteristics. The definition should specify the applicability to inverters connected to LV and MV levels. The relevant specifications are also contained in the recent IEEE 1547-2018 standard.

2.2.3.2 Automatic reconnection

Current Provisions	The Distributed Generation Regulations state that, once disconnected from the Electric Distribution System, the Generation System will measure the voltage and the frequency at the Common Connection Point. The Generation System will reconnect once the voltage and frequency remain at adequate levels for at least five minutes.
International Experience	Conditions for automatic reconnection after disconnection due to disturbances should be specified. Specifying reconnection conditions and ramp rates is common international practice. In Germany, VRE generator facilities may automatically reconnect when: All line-to-neutral voltages in the distribution grid at the connection point as well as the frequency in the distribution grid have remained in the normal operating range for a pre-defined amount of time. After automatic reconnection according to the above conditions, the active power generation increase of the solar power generator facility must be limited (not required after manual reconnection).
Recommendation	The current requirement is aligned with international requirements. However, it is recommended to clearly define “adequate level”, i.e. defining the conditions when the disturbance is to be considered over.

2.2.3.3 Anti-islanding protection

Current Provisions	Article 24 of the Distributed Generation Regulations includes a requirement for Anti-Island Protection. The Generation System will have the protection needed to prevent it from energizing a deactivated circuit from the Distributor. Should an island situation arise, the Generation System should be disconnected from the Distribution System in less than 2 seconds. It further specifies that that the Distributor may require the applicant, and he will be obliged to provide it, a communication channel between the Applicant's Generation System and the Distributor protection devices, in case the Applicant's Generation System is capable of maintaining an Electric Island. This communication channel will serve to coordinate the automatic disconnection of the Generation System when the feeder protection operates.
International Experience	If a feeder or grid section with distributed generators connected is tripped either by a fault or manually by the operator for any other reason, the generators on that feeder need to detect this and disconnect.
Recommendation	Aligned with international requirements (IEEE 1547-2018 Standard).

2.2.4 Monitoring/Controllability/Forecasting

2.2.4.1 2.2.4.1 Monitoring/ Controllability

Current Provisions	Article 23 of the Complementary INGERE Regulations includes that all INGERE, connected to the Transmission system and / or the Distribution system, must have adequate communication systems to **transmit the information required** by the Control System Supervisor and Data Acquisition (SCADA) of the CCE in accordance with the specifications established in the Connection Code. The IEEE 1547 includes guidelines on monitoring and control implementation possibilities, providing examples (case studies). The monitoring needs vary with size and location of the PV system.
International Experience	Solar power generator facilities that implement power control mode must be equipped to be capable of receiving corresponding target values from the distribution operator and/or transmission operator. In Germany, PV units below 30 kWp must either be controllable or always curtailed at 70% of its peak power[3]. All larger units must be remote controllable, which means that the unit must have the provisions for remote control.
Recommendation	Require at least larger PV systems to be **capable** of establishing communication between the built-in generator controls and the distribution company. The system capacity size above which requirements apply must be defined. This capacity size limit should be gradually reduced over time with increasing PV penetration in the overall system.

3 Curtailing PV to 70% of the panel capacity is not such a strict requirement because the PVs usually do not reach more than 75-80% of their rated panel output. There is actually very little energy lost when using this requirement (around 3% of annually lost energy). The PV capacity on a feeder is limited by the rated power of assets connecting it to the higher voltage levels. If the PV capacity on a low voltage feeder is limited to the transformer power rating, there will most likely be an overestimation of the PV output power because PV systems almost never reach their peak power (especially in Germany). Therefore, by curtailing this peak power in the few occasions it is reached in a year, would result in little lost energy but would bring the benefit of allowing to raise the amount of PV that can be integrated.

2.2.4.2 Scheduling/ Forecasting

Current Provisions	ARTICLE 31 of the Complementary INGERE Regulations states solar installations connected both to the Transmission system as to the Distribution system, will deliver to the OC, in **the opportunity that this requires**, the power curve and net hour dispatch, to be considered in the Schedule of the Daily Operation (PDO), in reprogramming and during Real Time Operation carried out by the CCE. Article 33 states that the non-manageable INGERE Agent, will update its forecasts daily and send them to the OC, in the term established in Art. 208 of the RLGE. Based on these forecasts, these facilities will be included in the PDO carried out by the OC.
International Experience	Operating codes often contain medium to short-term forecasting requirements, intended to aid the DSO in preparing their own daily or weekly load forecasts for the transmission system operator (TSO) and/or the balancing responsible parties. These are typically rather basic, with a focus on generators and large consumers being required to notify the DSO of large deviations from the usual load or generation patterns, but also usually include a provision that allows the DSO to require more detailed forecasts from individual actors in the system if deemed necessary. In the UK and Ireland for example, requirements are usually imposed on generators directly connected to the medium voltage level (10 – 50 kV), or generators above a certain capacity (between 1 and 5 MW). Typical data required includes the expected unavailability of a facility within the next six or twelve months, and expected deviations from the usual demand or generation patterns on a daily or weekly basis. Generation forecasting requirements for renewable energy generators on a daily basis (short term) are typically not required in distribution grid codes. Daily forecasting of both load and renewable feed-in in the distribution grid are within the responsibility of either the DSO or the TSO, depending on the country context and the electricity market structure.
Recommendation	Define voltage level and generator capacity size above which requirements apply. Clearly define requirements for these. Forecasting of VRE by distribution grid area is recommended to be done by the DSO with increasing shares of PV in the system, however, this is not to be governed by the distribution code. It is not necessary for the DSO to forecast small individual installations connected to the distribution level. Only the TSO needs to include these in its forecast, e.g. by scaling the large PV plants' forecast by a factor in order to include the small-scale PV systems

2.2.5. Connection process

2.2.5.1 Simple interconnection process

Current Provisions	As stated in the Distributed Generation Regulations, the Review Process for Simple Interconnection applies to the Applicant whose Generation System meets the criteria of Article 22 of this Regulation, Certification and Approval of Equipment. The main conditions to be met to be eligible for the "simple interconnection process" are to: • The Aggregate Capacity of all Renewable Generation Systems connected to the same feeder, including the proposed Generation System, shall not exceed fifteen percent (15%) of the annual Peak Demand of such feeder; • The system capacity should be below 25kW (single-phase equipment) or bellow 200kW (three-phase equipment) • Have an aggregated capacity below the capacity of the distribution transformer (kVA) • Have an aggregated capacity below 1% of the maximum demand of the system; • Fulfil all additional requirements of feeder and protection. Indicated in Chapter VII of the same document.
2019 Draft Proposal	In the new draft, no mention was found to the conditions to be eligible for the simple interconnection process. It is mentioned that applicants for connection include: (a) systems with a capacity up to 25kW (single-phase) and that can connect after a technical evaluation conducted by the DSO or (b) applicants with a system with capacity greater than 25kW (single-phase) and from 200kW up to 1500kW (three-phase) which will be evaluated based on a complementary study to be conducted by the DSO.
International Experience	Germany has a fast track application and approval procedure in place for rooftop PV below 135 kW, which allows new installations to be connected within a few days in the best case. This is connected to the German Renewable Energy Act, in which the DSO may not reject a connection application, but only postpone it if the grid has to be reinforced first, which has to be paid by the DSO ("shallow connection charge"). This is not only a grid code issue and tied to national renewable energy policy. Barbados has a fast track system for distributed generators with an aggregate capacity up to 150kW. The prospective owner submits an application for proposed connection, to which the DSO analyses and replies within 6 weeks if the application was approved and if modifications are required, the latter in case the PV system is found to negatively impact the stability and/or security of the power system. The DSO may also refuse the application for connection in case modifications are deemed insufficient as mitigation measures (a rationale is to be submitted to the client). If the application is approved, the process then proceeds to obtaining licenses, submitting documents, installing the system, inspections/tests and connection. For applications from generators above 150kW, the DSO will conduct a connection impact assessment and provide an answer for the application within 6 months.
Recomendación	It is recommended to have additional filters in the interconnection process[4], which allow for a faster process for small systems that wish to connect to the LV level. With the additional filters created, the 15% limit filter should not be applied for small units (for example units below 10kW, as per FERC example of lessons learnt).

4 There is a specific task in this project to propose a detailed interconnection process taking into account the simulation model developed and results.

2.2.5.2 Complementary Study requirements in the connection process, and associated costs

Current Provisions	In the Distributed Generation Regulations, it is stated that, when applications do not meet the simple process requirements, these need to undergo complementary studies, which will determine if changes to the distribution system are necessary or if changes to the client's generation system must be made before connecting. The distribution company will list the complementary studies needed in the evaluation letter, together with an estimate of costs and time for the studies. The client has 30 calendar days to accept the study and costs and submit any information needed for the studies. Studies will only begin after costs have been paid. The cost of any changes required to the distribution system/ or to the generation system that wants to connect are to be **covered by the applicant**. The results of the complementary study are valid for 1 year. The complementary studies might include: Power Flow / Voltage Fluctuations; Short Circuit / Protection and Protection Coordination; Verification of the Grounding Design.
International Experience	DSO is responsible for grid impact studies. Good practice is to clearly define when the studies are to be conducted (i.e. when units do not apply for a simple interconnection process). Regarding costs, good practice is to have shallow connection charges, where applicants do not pay for grid reinforcements beyond the connection point. Nevertheless, this varies greatly among countries.
Recommendation	Discuss the possibility of switching to shallow connection charge and recover the cost from all consumers and/or applicant via grid fees.

2.2.5.3 Validity of the connection agreement

Current Provisions	According to the Distributed Generation Regulations, the connection agreement is valid for 5 years. The agreement can be renewed every 5 years, upon evidence submitted by the Client of equipment maintenance and testing to the Protection.
2019 Draft Proposal	In the new Draft, the validity of 5 years is no longer specified. Instead, it is stated that the Agreement shall be as effective as the Customer Power Supply Agreement, unless: (a) is terminated by mutual agreement of the Parties, (b) is replaced by another Distributed Generation Agreement, (c) terminates the electric service contract of Customer, or (d) is terminated for breach by either Party of any of the Terms and Conditions of this Agreement.
International Experience	Connection agreements are often of 20 years, in line with the lifetime of PV systems. Lower periods yield uncertainty for the investment. In German grid codes for example, the validity of the connection agreement is not specified, however, the feed-in tariff or bonus is granted for 20 years. Non-compliance to periodic tests is a motive to end the agreement. Good practice is to have the periodic tests aligned with the code in force when each unit was connected (i.e. not to use periodic tests to enforce compliance of older units to codes published after the unit was connected). For this, the code applicable to each unit must be kept in a DSO database.
Recommendation	New Draft aligned with international good practice. Retroactive applicability of grid codes should be verified and avoided (if present).

2.2.6. Compliance

2.2.6.1 Certification and approval of equipment

Current Provisions	The Distributed Generation Regulations states that an equipment is considered certified and approved when it complies with the requirements of the IEEE 1547 or UL 1741 standard, as well as with IEEE 519 (which includes requirements related to Harmonics and flicker) and with the Minimum Requirements Certification procedures of Efficiency issued by the corresponding authority for equipment operating in parallel with the Distribution. The manufacturer, distributor or owner of the equipment is responsible for submitting the documents and samples required by the Technical Department of the Distributor and to verify and demonstrate that the equipment meets the requirements established in the aforementioned standards. The DSO will have a list of approved equipment, in such a way that the certification documentation must not be submitted again if the proposed equipment model is previously approved.
2019 Draft Proposal	The generator unit shall comply with the requirements set out in IEEE 519, IEC-61000-3-2: Harmonic content and flicker control requirements.
International Experience	German good practice states that compliance with the technical requirements for solar power generator facilities and protection functions shall be proven by means of written manufacturer statements of compliance for the corresponding product model/type.
Recommendation	Aligned with international requirements (IEEE 1547/ UL 1741 Standards). Further IEC standards could be added.

2.2.6.2 Commissioning Tests

Current Provisions	As stated in the Distributed Generation Regulations, before operating in parallel with the Distributor's Electrical System, the Applicant or his representative will carry out tests on the Protection Equipment of his Generation System. They will comply with the applicable standards and codes, including the operational and protection requirements of the IEEE 1547 and IEEE 519 standards. These tests will be the responsibility of the Applicant and will be certified by a Chartered Engineer. A list of tests is given.
International Experience	Commissioning tests for control and technical performance parameters.
Recommendation	Aligned with international good practices. Further IEC standards could be added.

2.2.6.3 Periodic Tests

Current Provisions	As stated in Article 27 of the Distributed Generation Regulations, the Client will test all the Protective Equipment, including the Manual Switch, at the time of installation and within a period not exceeding six months prior to renewing the Interconnection Agreement. The tests shall meet the operational and protection requirements of the IEEE 1547 standard presented in ANNEX B of this regulation. The Distributor will have the right to preventively disconnect the Generation System, if the Client modifies the Generation System without their consent, until they verify that the modifications do not jeopardize the security and reliability of the Electric Distribution System.
2019 Draft Proposal	Periodic tests are no longer aligned with the 5 years renovation time frame of the connection agreement. No mention to periodic tests was found in the new Draft.
International Experience	Ex-post monitoring of performance and flagging of non-compliance during operation. DSO has the right to disconnect non-compliant plants until compliance is proven. In the UK, Ireland and Malaysia, DSOs are usually allowed and/or required to monitor supply quality in the system and conduct periodical compliance tests [1] ,[2], [3]. In the case of Barbados [4], customers are additionally required to conduct power quality monitoring and provide the measurement results to the DSO/utility.
Recommendation	Periodic tests are already required in the current regulation to follow guidelines in the IEEE 1547 standard. It is recommended to define responsibilities of the DSO and of the Client as well as a timeframe for these tests.

2.2.7 Metering

2.2.6.1 Metering equipment requirements

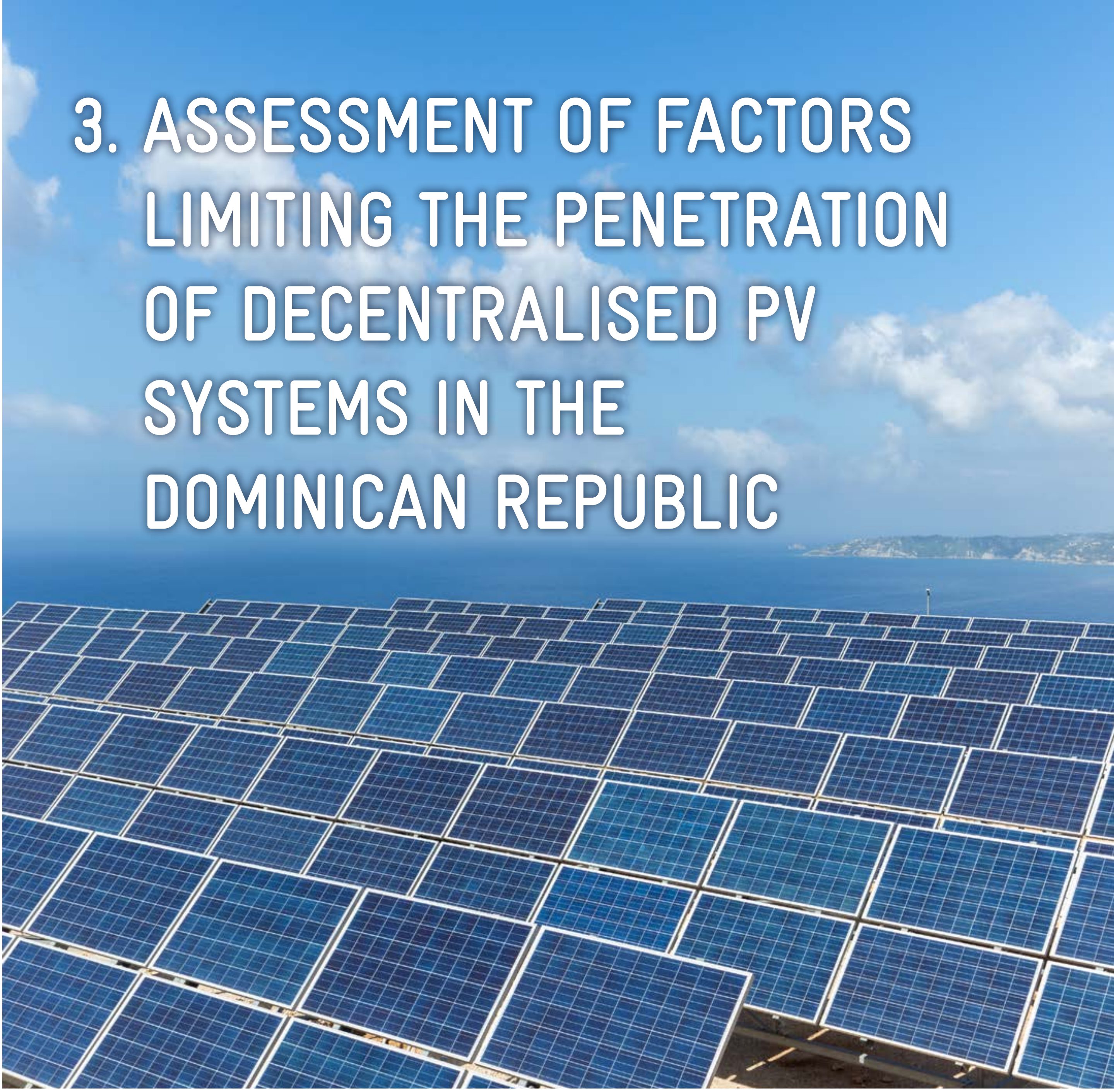
Current Provisions	According to Distributed Generation Regulations, customer metering will be enhanced to include bi-directional reading and historical load profile functions. The Distributor will install a meter with the following features: 1. Meters for Residential Clients connected at secondary distribution voltage level: a. Fully electronic. b. Bi-directional, with separate energy readings received and delivered. c. With memory to record consumption at hourly intervals with a minimum of two memory channels, kWh delivered and kWh received. d. Able to communicate through the Distributor's remote measurement system. 2. Meters for connected Medium Voltage Clients (4.16, 7.2, 12.47, 34.5 KV, or any other distribution voltage used) are powered by Current Transformers and Power Transformers. Items a and d are identical to above, and: b. With measurement in four quadrants, measuring active and reactive energy, received and delivered. c. With memory to record a minimum of 60 continuous days of consumption at 15-minute intervals with a minimum of five memory channels, kWh delivered, kvarh delivered, kWh received, kvarh received.
2019 Draft Proposal	Item 1 is modified to refer to clients connected to the low voltage distribution system, and the duration of the interval is not defined. Item 2 is modified to refer to clients connected to low voltage with Demand and to medium voltage with indirect measurement. Additional requirements are to record kW and kvar delivered and received.
International Experience	In Germany two independent meters are used (for PV and load). Whilst for countries with net metering schemes, one single meter is often used capable of metering bi-directional flows. In countries such as the UK and Ireland, also Code of Practices [5] are published that offer in very great detail the procedures related to metering. Such codes are however established to unify metering across many meter operators, therefore improving competition in such markets. In the context of countries with only a few meter operators, such detailed provisions may not be necessary.
Recommendation	It is advised to refer to meter related standards, e.g. from the IEC, that foster alignment with other countries who refer to similar standards. Common standards are found for example in Metering Codes from the EU and its member states.

2.2.7.2 Net Metering Scheme

Current Provisions	According to the Net Metering Regulations, Net metering is possible for: residential customers with RE systems up to 25kW or Commercial/ industrial customers (or agricultural, educational institutions or medical hospital clients) with RE systems up to 1MW. The distribution company will install a bidirectional metering device. The client will pay the difference of such device and the standard device. Required characteristics of the metering device are listed and include that it must be able to communicate via the remote measurement system of the Distributor. When client draws more than produces, he pays for: net energy, monthly fixed fee, demand fee (maximum demand, maximum demand during peak hours, maximum demand off-peak). In case the client produces more than is consumed, he will receive: a debit for the demand fee (based on maximum exporting power) and fixed fee, as well as a credit for the excess energy delivered to the grid, which will be considered in the next bill. If by December a credit still remains, the distribution company will pay 75% of the credit by 31st of January. The other 25% will be used in the efficiency and loss reduction programme of the distribution company.
2019 Draft Proposal	Any power generation installation greater than or equal to its consumption may not inject more than 10% of its demand into the network and in the event that the DSO requires more injection, he will have the power to manage its discharge to the network so that it does not disturb the circuit to which it would be injecting. In the case of regular customers with self-generation, the power requested to be installed should not be greater than the power demanded by the applicant, in the event that this value is exceeded, in order to supply the energy to the network, no more than the AUTHORIZED POWER can be discharged, which is determined after the Studies carried out by the DSO in response to a request for an interconnection of distributed generation. Furthermore, regarding the economic transaction of net metering: • Billing for energy and power consumption carried out by the client, and the credit for the energy that he exports, will be carried out based on the methodology of "NET BILLING". • The Fixed Charge shall be charged to the customer taking into account the assigned tariff or the level of consumption, regardless of whether the consumption is zero. • The Power Factor penalty will be assessed with the energies demanded from the grid. • In the case of energy injected into the distribution network, it will be valued at the average purchase price of energy from the distributor. To this price an expansion factor of energy losses will be applied. • Once the Energy and Power Withdrawn and the Energy Injected have been valued, the difference between these components (withdrawals minus injections) will be: (i) If as a result of the subtraction the value obtained is a balance in favour of the DSO, this value must be paid by the customer; (ii) If as a result of the subtraction the value obtained is a balance in favour of the customer, then the following arrangement will be made: The distributor will credit the customer with the balance in favour during the billing period and will apply it to the invoice of the next billing period. • At the end of the year, the user will be credited for any energy injected, accumulated and unused at the end of the billing period. The distributor shall recognize this credit, before January 31st of each year, and shall pay the customer 100% of the accumulated credit for Energy Injected into the distributor's networks according to the feasible payment mechanism available to the distributor.

International Experience	Best practices based on an IEA review of several countries where net metering is working include [6]: • Adapt regulatory framework as the number of prosumers increases; • Have clear and precise regulations (conditions for eligibility, connection procedure, responsibilities of parties involved, technical specifications); • Simplify administrative procedures as much as possible (also related to required studies); • Strengthen distribution companies' skills (to deal with new billing system, impact studies, etc) • Optimize the compensation scheme with a value that does not penalise the distribution company whilst still being attractive for customers. Solutions to not penalise the distribution company have been listed as: the value of injected kWh must be lower or equal to the average cost of electricity; or the quantity of injectable energy mut be limited by regulations; or distribution companies receive a financial assistance (may result in a tax). • Only compensate the actual injected energy (i.e. no compensation when a problem in the network occurs which prevents energy injection); • Ensure the payment of taxes on electricity consumption (tax payment on total energy consumption of a customer regardless if it was produced by the prosumer or by the utility) • The injectable power must not exceed the maximum mentioned in the sales contract, with the consumer being a net importer from the utility over a period of time (regardless of the self-consumption). Furthermore, a net billing mechanism is described in [7] to address some of the limitations of a net metering mechanism. Tariffs based on time or location are recommended, to reflect the cost of electricity at the moment of injection to the grid (e.g. more valuable for the system during peak hours) and at the different nodes (e.g. based on grid congestion). These lead to more flexibility in the system and allows consumers to support the grid based on price signals. In case of dynamic time of use tariffs, an advanced metering infrastructure is required to enable two-way communication on priced between retailers, system operators and prosumers.
Recommendation	The current net metering mechanism is overall aligned with the good practices of net metering schemes mentioned above. The suitability of the application of other compensation mechanisms for the Dominican Republic context can be analyzed, with the aim to further enable higher shares of renewable penetration in the system. The injection limit in the 2019 Draft (limit of 10% of the demand of the generation installation when greater than or equal to its consumption) could be increased or replaced in the future in a way to allow further injection without resulting in oversupply in the system and resulting grid integration challenges. Furthermore, the method in which, if the DSO requires more injection, he will have the power to manage the generator's discharge to the network so that it does not disturb the circuit to which it would be injecting could be clarified.

3. ASSESSMENT OF FACTORS LIMITING THE PENETRATION OF DECENTRALISED PV SYSTEMS IN THE DOMINICAN REPUBLIC



3.1 IDENTIFIED LIMITING FACTORS FOR DECENTRALISED PV INTERCONNECTION TO THE DOMINICAN REPUBLIC DISTRIBUTION SYSTEM

Based on the document assessment (described in Section 2), factors that might limit PV interconnection have been identified. These are either factors that reduce attractiveness of PV systems to project developers, or that technically limit the capacity allowed to be installed. These will be summarised next.

Limiting factors related to the connection process:

- In the regulations in place, when the aggregate capacity of all renewable generation systems connected to the same feeder, including the proposed generation system, exceeds 15% of the annual peak demand of such feeder, the generation system does not qualify for the **simple interconnection process**. This means that even small units would be required to pay for supplementary studies if they lead to exceeding the 15% limit stated. This limit is not mentioned in the 2019 Draft. Additional filters for the interconnection process in the Dominican Republic are necessary, especially for small residential systems connected to the LV system (for example, users with monomic billing, BTS-1, and BTS-2).

Adding an initial fast filter for small systems that wish to connect to the LV level is recommended to overcome the issue of the **15% limit** stated above (for example a filter for systems below 10kW, as per FERC example of lessons learnt). This issue is addressed in detail in Chapter 12, which proposes a new detailed interconnection process.

- **Deep connection charges** currently apply, with the cost of any changes required to the distribution system to be covered by the applicant. This can represent a great barrier for the applicant who would need to pay the reinforcement cost and might also represent some unfairness if similar-sized systems have connected previously to the same feeder and he is the "one too many" system that leads to the reinforcement requirement. It may be discussed the possibility of switching to having shallow connection charges, for example with applicants paying for grid reinforcements on the LV level but not on the MV level. MV related costs could be recovered from all consumers and/or grouping of applicants via grid fees.

- [Modified in 2019 Draft]: The **connection agreement is valid for 5 years** and can be renewed upon evidence submitted by the Client of equipment maintenance and testing to the Protection. This 5-year short time horizon, when compared to the 20 years typical lifetime of a PV system, brings uncertainty for the investment and might discourage project developers. The 2019 draft removes this 5-year agreement validity and establishes the validity to be aligned to the Customer Power Supply Agreement. This is aligned with international good practices.

Other limiting factors:

- The 2019 Draft specifies an **injection limit to generation plants of 10% of the demand** of the generation installation (when greater than or equal to its consumption). Although this is a limit which affects the operation of the plant, this limit might weigh negatively on the Client's decision to interconnect. This limit could be increased, or replaced when combined with other measures, in a way to allow further injection without resulting in oversupply in the system and associated grid integration challenges. It should also be specified over what period of time this injection limit applies (for example, one year).

- During the kick-off meeting with stakeholders, it was mentioned the existence of **RE installations** connected to the distribution system in the past and currently operational, which are **not registered and are therefore currently not completely visible to the DSOs and the regulator**. These older installations were indicated to have a significant total aggregated size (estimated to be in the order of 30 MW accumulated). Therefore, developing a strategy to register these units is very important in order to increase visibility of the DSOs on all RE installed in their systems, allowing to move towards higher VRE shares.

- **Retroactive applicability:** International good practice is that units compliant with older versions must not be retrofitted to comply with the new code when a new grid code enters into force. Facilities connected to the grid must follow the grid code in force at the date of connection. Existing facilities may be required to comply with updated grid code requirements in case of major changes or renovations to the facility. In this case, the "major changes" should be clearly defined. Retroactive applicability of new grid code requirements can be a major barrier to IPP involvement. The risk of having to upgrade a facility, especially a generating unit, at potentially high cost deters investments due to reduced financial planning security. In the 2019 Draft, it is stated that its purpose is to lay down the procedures governing the requirements of projects that are interested in being connected to the medium and/or low voltage grids. Therefore, it indicates applicability to new units and no retroactive applicability. Nevertheless, it is important to verify and ensured that no retroactive applicability exists in all other relevant regulations as this would represent a limiting factor for interconnection. This can be clarified with stakeholders.

3.2 REVIEW OF MOST PREVALENT ISSUES FOR INTEGRATING LARGE AMOUNTS OF DECENTRALISED PHOTOVOLTAIC GENERATION

Integrating high shares of photovoltaic generation to the distribution level may have negative impacts, which include:

- **Reverse power flows,** which can cause **voltage rises**, and can also cause **asset overload** and the need for expansion. However, an even distribution of PV installations in the distribution system reduces reverse power flows and expansion needs;

- **Changes to protection requirements:** high shares of VRE lead to reducing fault current in the system and may negatively impact protection schemes (e.g. formation of an unintentional island, sympathetic tripping, etc). Changes to protection requirements can be mostly solved on PV plant level by means of setting appropriate technical requirements (such as immediate disconnection during grid faults or, at high system-wide PV shares, fault ride-through capability in combination with zero-current mode);

- Required **changes to control strategies** in grid operation;

- Small PV systems have lower **impact on contingency reserve** requirements when compared to larger plants. However, unexpected geographically-large weather events (such as cloud fronts) affecting many systems simultaneously have the potential to vary solar PV generation considerably and unexpectedly within an hour. PV systems when in combination with storage systems have the potential to reduce spinning reserves requirements from conventional generators;

- **Need for increased cooperation** (and information exchange) between transmission and distribution system operators as well as ancillary services providers.

Some of these impacts can be reduced by requesting certain capabilities from the PV systems themselves. Solar PV technologies are already capable of providing several grid support services described in grid codes. The main services in use internationally today are voltage and frequency control. The technical and economic feasibility of grid support services provided by PV systems also vary between distribution and transmission systems, related to voltage levels and plant size therein. The need for grid support services is defined for each power system, depending on each system size and robustness as well as on VRE penetration levels, dispersion and implemented capabilities. These can be assessed using simulation-based studies (see Section 3.3).

Not all generators in a system need to provide grid support services in order to ensure safe system operation. Requiring certain advanced technical capabilities may be economically unfeasible and, depending on the system characteristics and current shares of VRE, often unnecessary. For each potential support service to be provided by PV system, a comparison with other methods of service provision should be therefore made in order to determine the most economically feasibility solution.

Furthermore, it is recommended to set the technical requirements based on current system needs, avoiding unnecessary costs associated to implementing more complex capabilities. However, expected future needs should also be taken into account, as PV systems have a lifetime of 20 years and retrofitting equipment is costly.

3.3 ROLE OF SIMULATION-BASED STUDIES IN THE ANALYSIS OF IMPACTS OF HIGH SHARES OF DECENTRALISED PV ON THE DISTRIBUTION SYSTEM

Simulation studies are highly recommended for the system planning and design phase of a power system, to assess the impact of high shares of renewable generation, such as those identified in the previous section. Simulation study objectives include:

- Identification of the impact of new technologies installed in the grid and the sensitivity of grid parameters;
- Identification of PV hosting capacity of the grid at its current status;
- Identification of solutions such as enabling technologies to increase PV hosting capacity of the grid or the need for grid reinforcements;
- Verify the benefits of current and potential grid code requirements in scenarios with increasing shares of renewable generation and allow to identify the need for modifications/ improvements early on.

IEEE 1547 recommends simulation studies to assess the impact of distributed generation in the system. These enable the analysis of: the contribution of PV system fault current for faults in any location within the secondary side; comparison of loads with PV generation within the different areas of the grid; response of PV systems to voltage and frequency deviations, among others.

Study types in the distribution level typically include:

- Load flow studies to assess grid overloading, sensitivity of voltage on a feeder and reactive power requirements;
- Static and dynamic short circuit studies to evaluate protection and Low Voltage Ride Through (LVRT) requirements.

For these studies, a more accurate power system model will yield better results. More accurate models are obtained when grid details are well represented, including models of generation units. Whereas generator simulation models are typically only requested in grid codes to be provided by large generators (typically connected to high voltage level), when VRE generation shares in the distribution system becomes significantly high and contribute to a significant portion of the nationwide generator capacity, these can also be requested for lower voltage levels. Such model will typically include active and reactive power capabilities, protection settings and fault-behaviour (voltage ride through, response to frequency deviations).

Furthermore, modelling an entire distribution system is not necessary in order to verify the impact of higher shares of VRE generation. Selecting and modelling representative feeders allows to have a general overview on the system impacts without increasing the time and complexity of simulations. Transmission system issues and impact on the entire power system are of minor interest for most distribution grid studies. For this reason, the transmission grid is mostly modelled as a slack bus, with the placement of the slack bus being determined according to the focus of the study (usually at the power transformer that connects the distribution system to the transmission system). Furthermore, detailed grid data is often unavailable for lowest voltage levels. In such cases, and when the focus of the study is not on low voltage grid issues, it is common practice to represent feeders or grid areas supplied by a single connection in low voltage grids by their load/generation equivalents (a PQ node, reflecting the active and reactive power that flows into a distribution feeder).

Simulation-based studies and complexities vary according to their objective. The studies referred to in this section are aimed at analysing the impact of VRE in the distribution system as a whole and differ from the complementary feeder-specific studies required for certain installations that apply for interconnection to the system (discussed in Section 2.2).

The feeder selection methodology, actual selected feeders, simulation methodology and proposed technical solutions to be analysed in the Dominican Republic distribution level simulation studies are outlined in the report "feeder selection and simulation methodology" delivered as part of phase 1 of this project.

4. DISTRIBUTION FEEDER SELECTION

The following medium voltage feeders have been selected. The explanation for the choice of the feeders is described in the subsequent chapters.

EdeNorte:

- ALMA101
- DAJA104
- MOCN106
- VOLG101

EdeSur:

- AHON104
- EMBA102
- KDIE104
- MVIE106

EdeEste:

- EBRI03
- HAMY01
- HI6904
- ROPU02

4.1 REPRESENTATIVE SELECTION

The objective was to select a representative sample of MV feeders that will be used in the subsequent simulation analysis (described in chapter 2). As much as possible, the selection should represent the different feeder characteristics in the Dominican Republic.

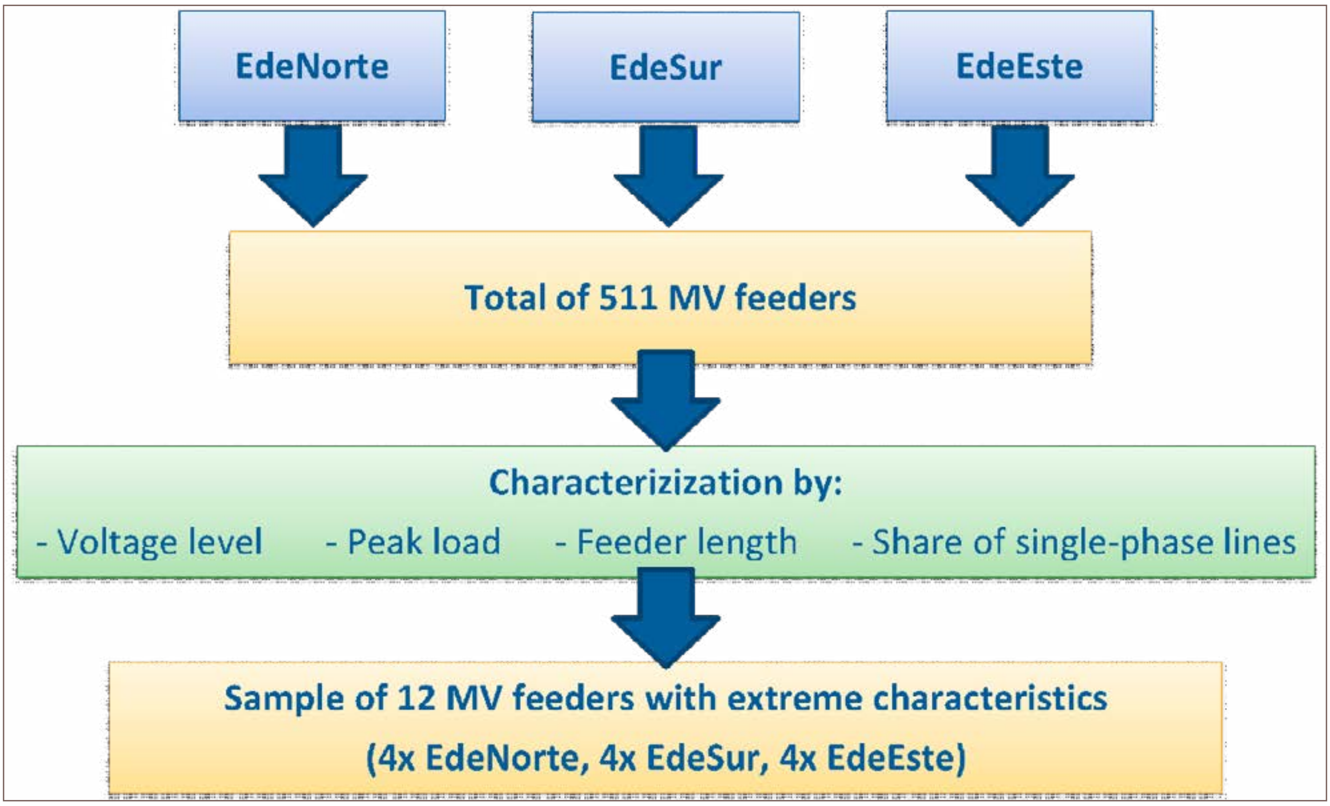
Due to time and effort limitations, it was decided that the study will look at a total of 12 feeders, i.e. 4 feeders per distribution system operator (DSO). However, selecting a representative sample of 4 feeders for each DSO individually is challenging as feeder characteristics can certainly vary widely.

However, many MV feeders will have similar characteristics across the DSOs due to similar planning criteria and line types used. Therefore, it was decided to use the full database of feeders across all DSOs and select a representative sample of 12 feeders from the total feeder number.

The full range of feeders can be characterized and for each characterization category one feeder can be selected, so that as a result, for each DSO, 4 feeders are selected. This allows to represent feeders from all DSOs, while at the same time providing a more comprehensive analysis. Therefore, when analysing the results, it is important to look at the full analysis and not only the results for the feeders of one of the DSOs.

Figure 5 illustrates the process.

Figure 5: Process of MV feeder selection



4.2 FEEDER CHARACTERIZATION

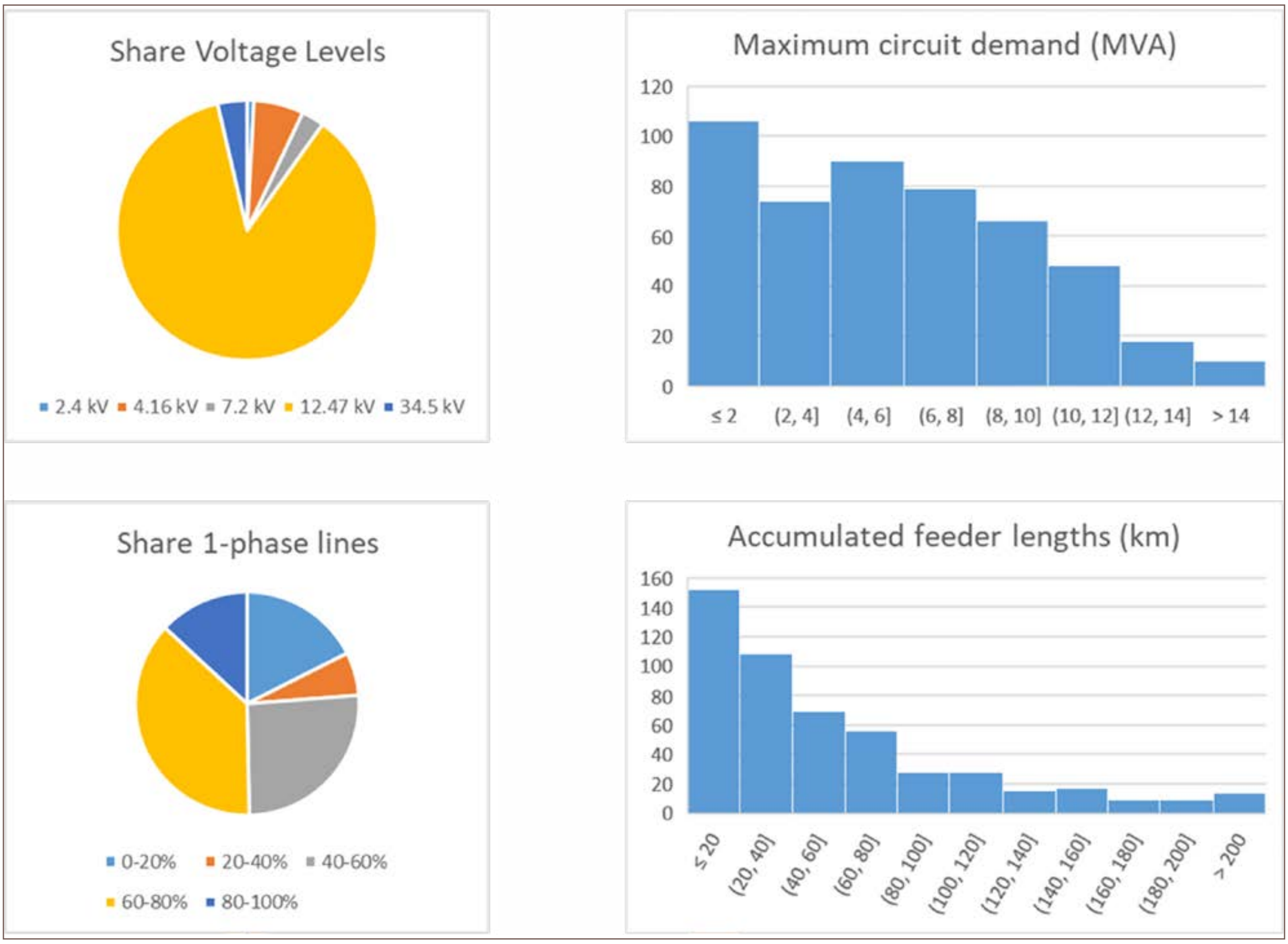
When characterizing MV feeders, certain factors are particularly crucial. This concerns for example the differences between rural and urban areas. In urban areas, there may be higher demand as well as more industrial customers, while in rural areas line lengths are typically longer as customers and villages are more interspersed and more customers may be connected by single-phase lines. Also different voltage control setpoints and thresholds are applied between rural and urban areas.

Therefore, the feeders were characterized by the following categories:

- Voltage level
- Accumulated length of feeder and branches
- Share of single-phase vs. three-phase lines
- Peak load

These consist also of the most important features for the PV analysis. The lower the voltage level and the longer the feeder length, the higher is the impact of PV for example on the voltage rise. Single-phase lines may be overloaded already at lower PV penetration levels and lead to unbalances. The load may alleviate the PV impacts. Figure 6 shows how the different feeders are distributed across the various categories.

Figure 6: Characteristics of all 511 MV feeders



As shown in Figure 6, 12.47 kV feeders represent almost 90% of all MV feeders. Most feeders are relatively short and usually consist only of a single branch. However, there are also some lines with very high total feeder length and many branches. With regard to the share between single-phase and 3-phase lines within each feeder, all types of feeders can be found, ranging from purely 3-phase systems to purely single-phase systems. Also, the peak demand varies widely, with some feeders (typically at higher voltage levels and shorter lengths) having more than 14 MVA of peak demand.

4.3 FEEDER SELECTION

A selection of feeders was taken that show both feeders with extreme characteristics as well as commonly found feeders. The goal of this selection is to show, on the one side, which PV penetration levels should always be safe to integrate (looking at the extreme/most problematic cases) and, on the other side, which PV penetration levels are in most feeders applicable (looking at the commonly found feeders). The results from the overall analysis will then be used to find new definitions for regulating the maximum PV penetration level.

With regard to the feeders with extreme characteristics, for each category of characteristics (described in chapter 2.2), the extreme cases have been considered. For example, within the 'feeder length' category both very short as well as very long lines are chosen.

The selection for each possible combination of categories can be seen in Table 1. This excludes the different combination for voltage levels: As voltage levels are predominantly 12.47 kV, only a feeder with a low voltage level, i.e. 4.16 kV, has been chosen to show PV limits in such a case.

For each category combination, one feeder was chosen from the list of recommended feeders for selection, that has been provided by the DSOs. As far as possible, feeders were chosen that have already today a high share of PV. The selected feeders are depicted in Table 1.

Table 1: Combination of extreme categories with one selected MV feeder per combination

VOLTAGE LEVEL	PEAK LOAD	FEEDER LENGTH	SHARE 1-PHASE	SELECTED FEEDER	DSO
12.47 kV	Low	Short	Low	EMBA102	EdeSur
12.47 kV	Low	Short	High	MOCN106	EdeNorte
12.47 kV	Low	Long	Low	DAJA104	EdeNorte
12.47 kV	Low	Long	High	ALMA101	EdeNorte
12.47 kV	High	Short	Low	MVIE106	EdeSur
12.47 kV	High	Short	High	AHON104	EdeSur
12.47 kV	High	Long	Low	HI6904	EdeEste
12.47 kV	High	Long	High	HAMY01	EdeEste
4.16 kV	Low	Long	High	ROPU02	EdeEste

On top of that, an additional three feeders were chosen that show common characteristics and were recommended by the DSOs. These are feeders that also already show very high PV penetration levels. Table 2 shows the final feeder selection including their characteristics.

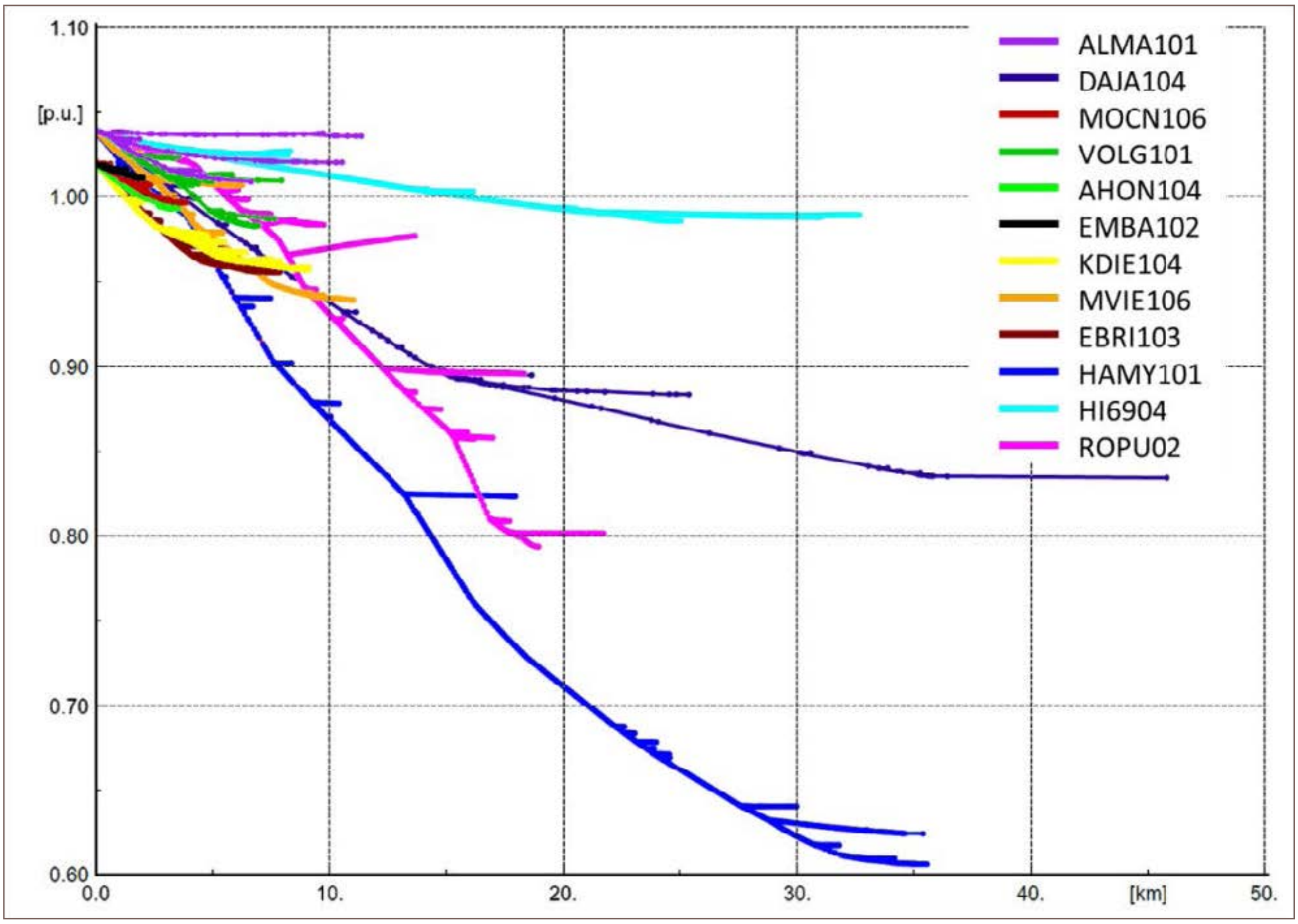
Table 2: Characteristics of the 12 selected MV feeders

SELECTED FEEDER	VOLTAGE LEVEL	PEAK LOAD	FEEDER LENGTH	SHARE 1-PHASE	PV SHARE
EMBA102 (EdeSur)	12.47 kV	4.7 MVA	12 km	22%	9.1%
MOCN106 (EdeNorte)	12.47 kV	4.4 MVA	29 km	63%	20.6 %
DAJA104 (EdeNorte)	12.47 kV	2.8 MVA	153 km	68%	1.7 %
ALMA101 (EdeNorte)	12.47 kV	1.8 MVA	132 km	90%	4.1 %
MVIE106 (EdeSur)	12.47 kV	8.3 MVA	31 km	26%	15.5 %
AHON104 (EdeSur)	12.47 kV	7.1 MVA	27 km	44%	17.4 %
HI6904 (EdeEste)	12.47 kV	5.4 MVA	117 km	41%	0.9 %
HAMY01 (EdeEste)	12.47 kV	7.9 MVA	187 km	81%	10.4 %
ROPU02 (EdeEste)	4.16 kV	3.6 MVA	95 km	64%	0 %
Additional feeders with high PV shares					
EBRI03 (EdeEste)	12.47 kV	9.7 MVA	66 km	53%	19.7 %
KDIE104 (EdeSur)	12.47 kV	10.1 MVA	119 km	72%	10.7 %
VOLG101 (EdeNorte)	12.47 kV	6.7 MVA	76 km	66%	69.4 %

Figure 7 shows the voltage-distance plots during peak demand of all selected feeders. As can be seen, feeders may vary with respect to their distance from the substation, the severity of voltage drop, the number of branches, and the level of loading of the lines (not depicted). These are all influenced by the categories described in chapter 2.2.

Already here, it can be seen that voltage issues are more critical in some feeders which also limits the amount of PV to be added, while in other (short) feeders, there are no voltage issues, hence, PV penetration is mostly limited by maximum line loading.

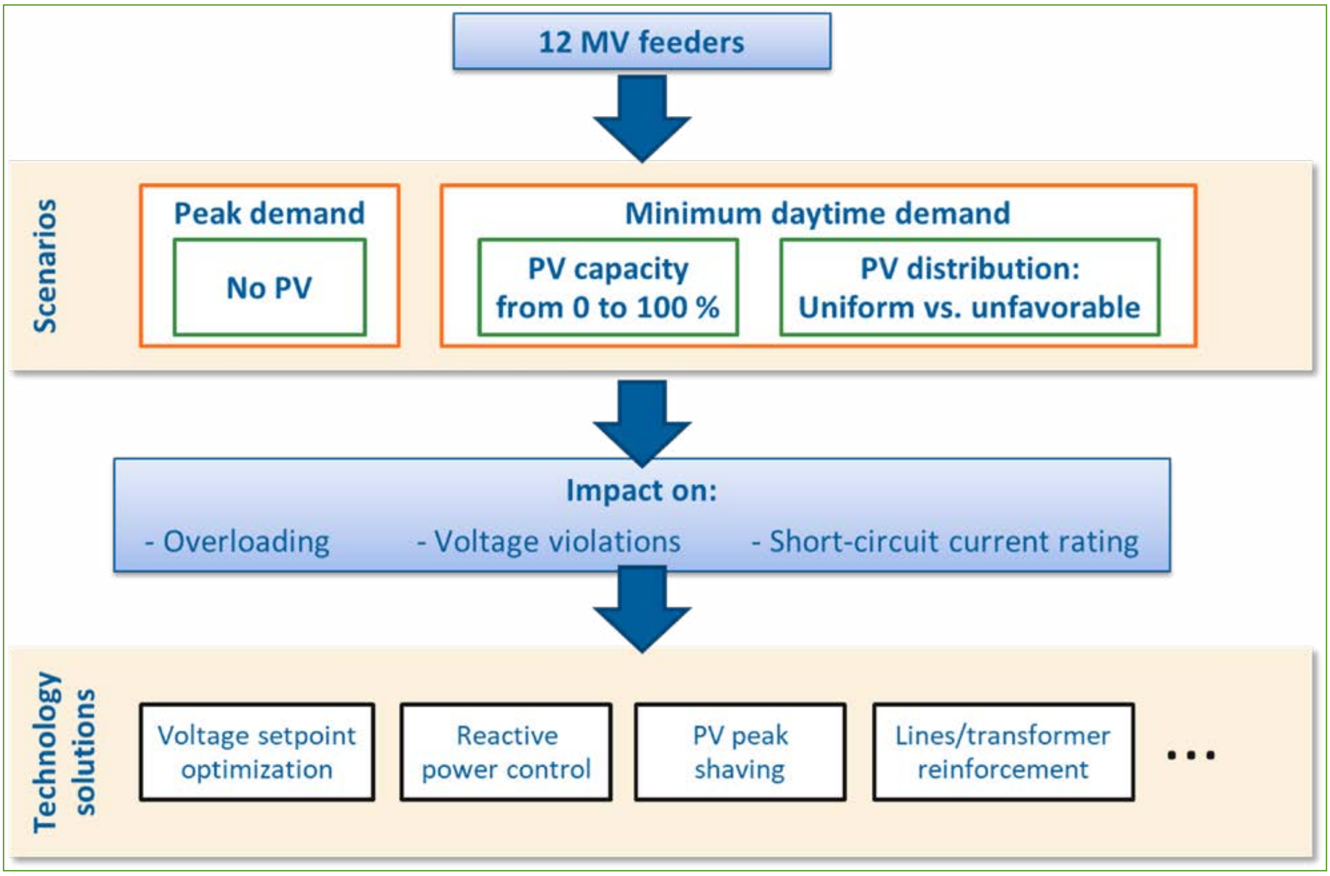
Figure 7: Voltage-distance plots of selected feeders during peak demand. Only one phase is depicted, not all three phases.



5. DISTRIBUTION FEEDER SIMULATION METHODOLOGY

Figure 8 shows a high-level overview of the simulation process. Each feeder will be simulated for the maximum demand case as well as different PV scenarios, varying the amount and distribution of PV. The impacts on overloading, voltage violations and short-circuit current rating will be analysed and maximum PV penetration levels determined. Finally, different technologies to increase the PV penetration level will be simulated to show the best techno-economic solutions.

Figure 8: Overview of the simulation process



In the following, the simulation methodology will be described in more detail.

5.1 DEMAND AND PV SCENARIOS

A number of different scenarios will be conducted to estimate the maximum PV hosting capacity in the analysed MV feeders.

First of all, the two worst-case simulation with regard to demand and PV generation will be analysed (see Figure 9):

- Peak demand, no PV generation
- Minimum day-time demand, peak PV generation

Furthermore, the amount of PV capacity in the feeder will be varied and the maximum PV penetration will be determined (see Figure 10).

Figure 9: Illustration of peak demand and peak generation scenario analysed

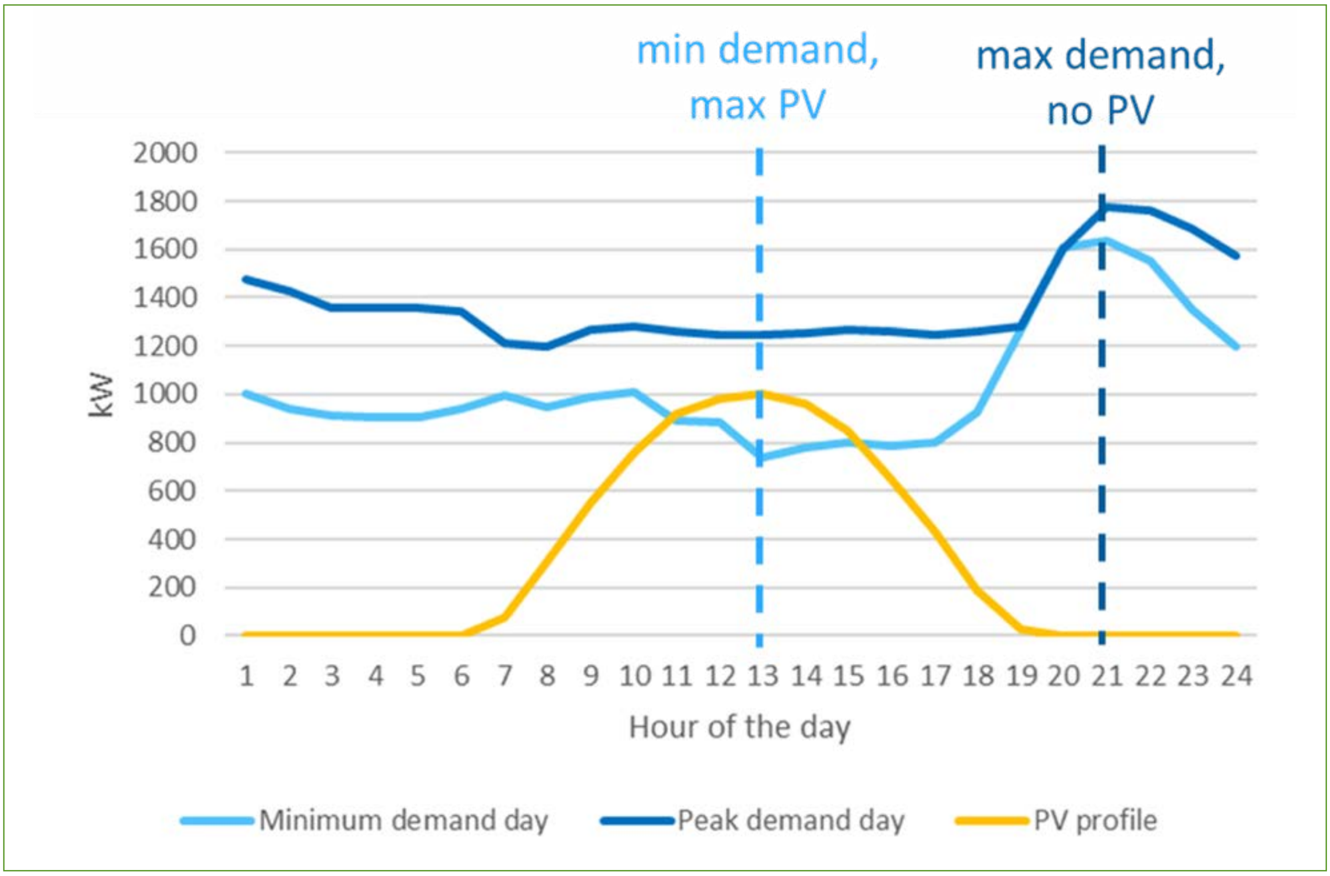


Figure 10: Illustration of PV scenarios

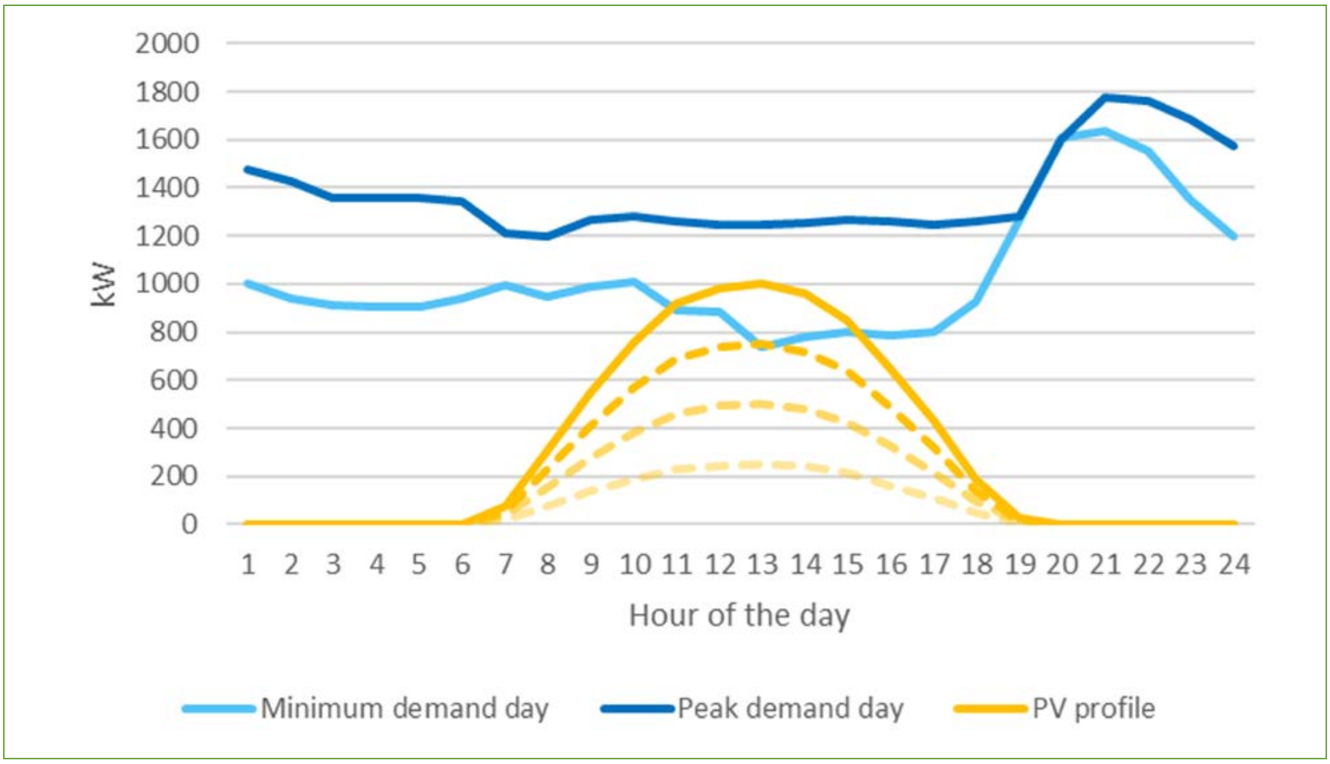
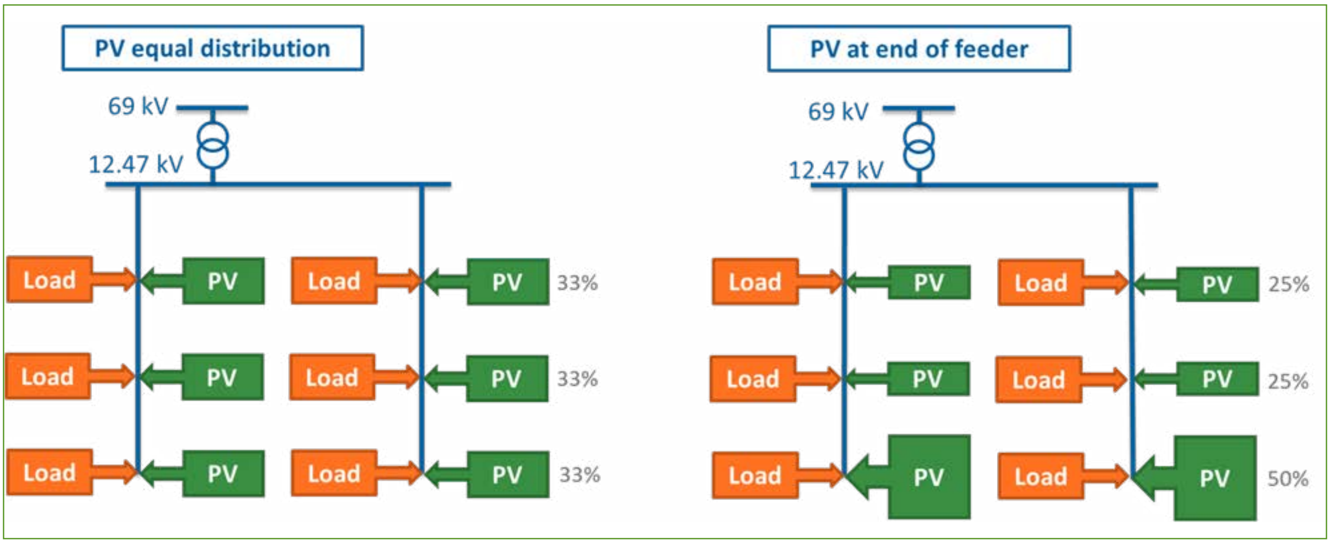


Figure 11: Illustration of PV distribution scenarios



With regard to the maximum PV penetration, different PV distribution scenarios will be analysed (see Figure 11):

- Uniform PV distribution across all MV/LV transformers, scaled by the respective distribution transformer size
- Unfavourable PV distribution towards the end of the feeder (25% of PV in first third, 25% in second third, 50% in last third of the feeder)

5.2 ANALYSED PV IMPACTS

The following impacts on the feeders will be analysed through simulation of the feeders in DIgSILENT PowerFactory:

- Overloading of MV lines and HV/MV transformers. (the latter was not evaluated as only individual feeders were analyzed)
- Voltage violations during peak demand vs. peak generation with minimum daytime demand
- Protection issues due to PV short-circuit current contribution.

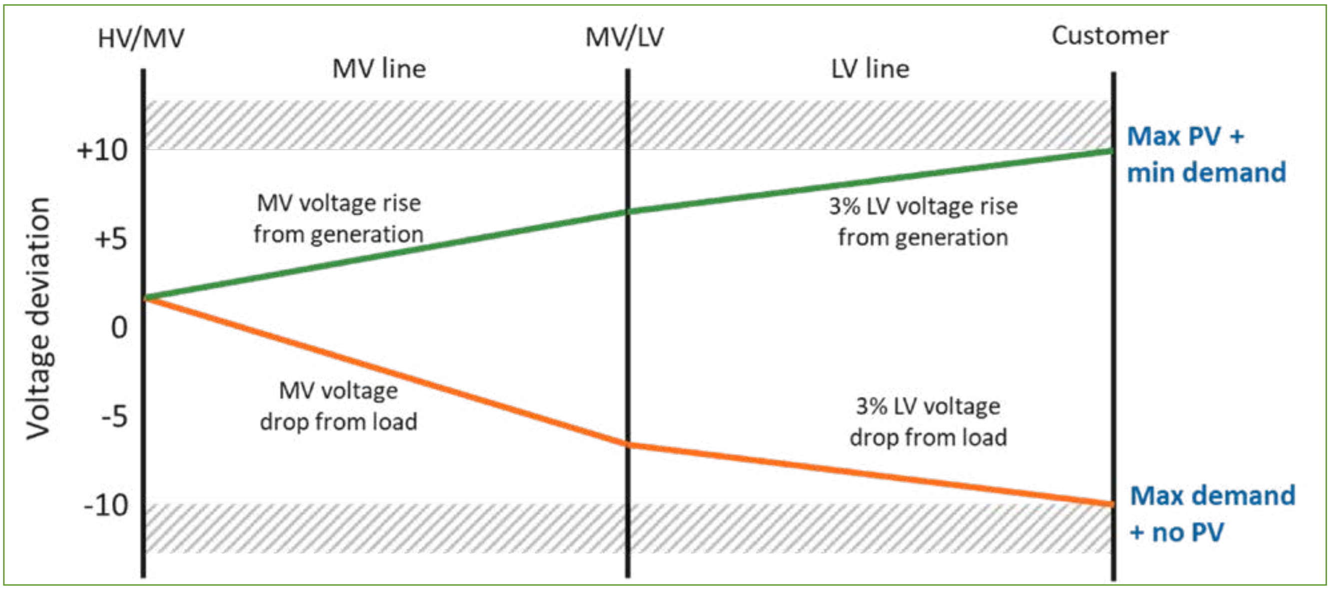
The following criteria are applied:

- Overloading (MV lines, HV/MV transformer) < 100%
- Voltage range in urban MV lines: ± 4.5 %
- Voltage range in rural MV lines: ± 7 %

The voltage range has been reduced from the original values defined in the General Electricity Law (urban: ± 7.5 %; rural: ± 10 %) in order to leave a spare voltage drop/rise in the LV network of 3 %. This corresponds to current planning principles identified in the Dominican Republic.

Figure 12 illustrates the maximum voltage fluctuations. An appropriate voltage control must ensure that no undervoltage issues arise during peak demand, as well as no overvoltage issues during peak PV generation.

Figure 12: Maximum and minimum voltage during peak demand and peak generation. Example on a rural feeder with ± 10 % voltage range.



6. MODEL SETUP

As described in chapter 4, the following feeders were selected through a screening process. These feeders comprise a wide range of possible feeder topologies in the Dominican Republic. They are suited to highlight at which PV penetration levels issues are most likely to arise and which feeder characteristics are most crucial to determine the maximum PV penetration level.

EdeNorte:

- ALMA101
- DAJA104
- MOCN106
- VOLG101

EdeSur:

- AHON104
- EMBA102
- KDIE104
- MVIE106

EdeEste:

- EBRI03
- HAMY01
- HI6904
- ROPU02

6.1 MODEL IMPORT

All feeders were simulated in the power system analysis software DIgSILENT PowerFactory. Currently, the DSOs are in the process of using PowerFactory for power system planning, however, at the time of the project, no PowerFactory models were yet available.

Therefore, models for EdeNorte and EdeSur were imported from the program PSS ADEPT, with an intermediate import/export through PSS SINCAL. Automatic interfaces to import data from PSS ADEPT to PSS SINCAL and from PSS SINCAL to PowerFactory are available in the respective programs.

In the case of EdeEste, no power system analysis software was used at the time of the project. Therefore, the PowerFactory models were built from Excel data sheets that were obtained from EdeEste's Geographic Information System (GIS).

6.2 GENERAL FEEDER CHARACTERISTICS

As is common in power systems all around the world, also in the Dominican Republic feeders are typically operated radial. Furthermore, most of the MV lines are supplied by overhead conductors. The majority of conductor types consist of aluminium alloy conductors (AAAC) and aluminium-conductor steel-reinforced cables (ACSR) in typical sizes of 1/0, 2/0 and 4/0, así como 477 ASCR y 559.5 ASCR.

6.3 CHARACTERISTICS OF LOW VOLTAGE NETWORKS

Low voltage networks are often fed through single-phase transformers, in particular in rural areas. In urban areas, also 3-phase transformers are quite common. LV lines are usually dimensioned in such a way that only a small voltage drop smaller than 3% is expected. Similarly, also for PV installations, a maximum voltage increase of 3% from transformer to the PV installation should be taken as a planning principle.

A simple formula to calculate the voltage increase induced by the PV within the low voltage network is as follows:

$$\Delta u\,[p.u.] = \frac{S_{PV}[VA] \bullet (R_{line}[Ohm] \bullet \cos(\varphi) - X_{line}[Ohm] \bullet \sin(\varphi))}{3 \bullet U^2[V]}$$

SPV is the installed capacity of the PV inverter. Rline and Xline are the resistance and reactance of all lines between PV generator and distribution transformer. Cos(ϕ) is the power factor of the PV power plant at rated power output and U is the line-to-ground voltage.

6.4 VOLTAGE CONTROL

The substation transformers of all feeders have enabled automatic tap changing, therefore allowing the voltage on the LV side of the transformer to be controlled.

According to current Dominican regulation, the applicable voltage ranges in urban grids is ± 7.5%, while for rural grids it is ± 10%.

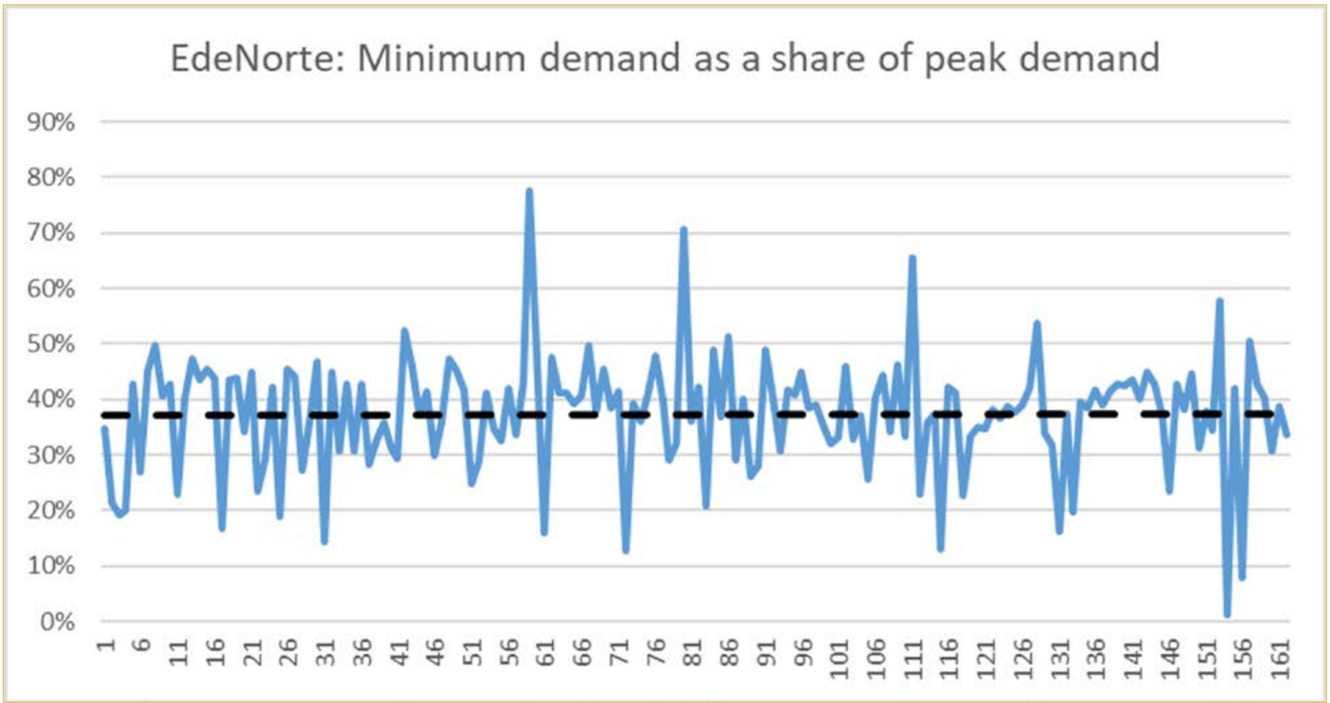
The voltage setpoints of primary substation transformers are typically approximately 1.02 p.u. for urban grids and 1.04 p.u. in rural grids, according to obtained information and measurement data.

6.5 MINIMUM LOAD CHARACTERISTICS

As described in chapter 3, the feeders will be analysed with respect to their maximum demand scenario as well as to their minimum demand scenario in combination with maximum PV infeed. The minimum demand size is a crucial factor in the maximum PV penetration: At very low demand, already low PV penetration levels can lead to reverse power flows and hence voltage and overloading problems within the distribution grid. On the other hand, if minimum demand is at a high share of peak demand, then a large amount of PV can be integrated without impacting the feeder significantly.

Hence, data on the minimum demand was obtained for the feeders. Figure 13 shows the relation between minimum and maximum demand for EdeNorte. As can be seen most feeders have a minimum demand of 20% to 50% compared to the peak demand. On average, the share is 38%.

Figure 13: Minimum demand as a share of peak demand for all feeders from EdeNorte. Black line indicates average share



In the case of EdeEste, no detailed data was available for the minimum demand. Taking a conservative estimate, considering the demand figures from the other DSOs, the minimum demand has been assumed to be 20% of peak demand.

6.6 MEASUREMENT DATA

Some measurement data has been analysed to verify the distribution network models and receive more information on load curves with respect to minimum and maximum demand, analyse the current impact that PV has on some feeders, and screen the feeders in terms of phase unbalances.

6.6.1 Daily load curve

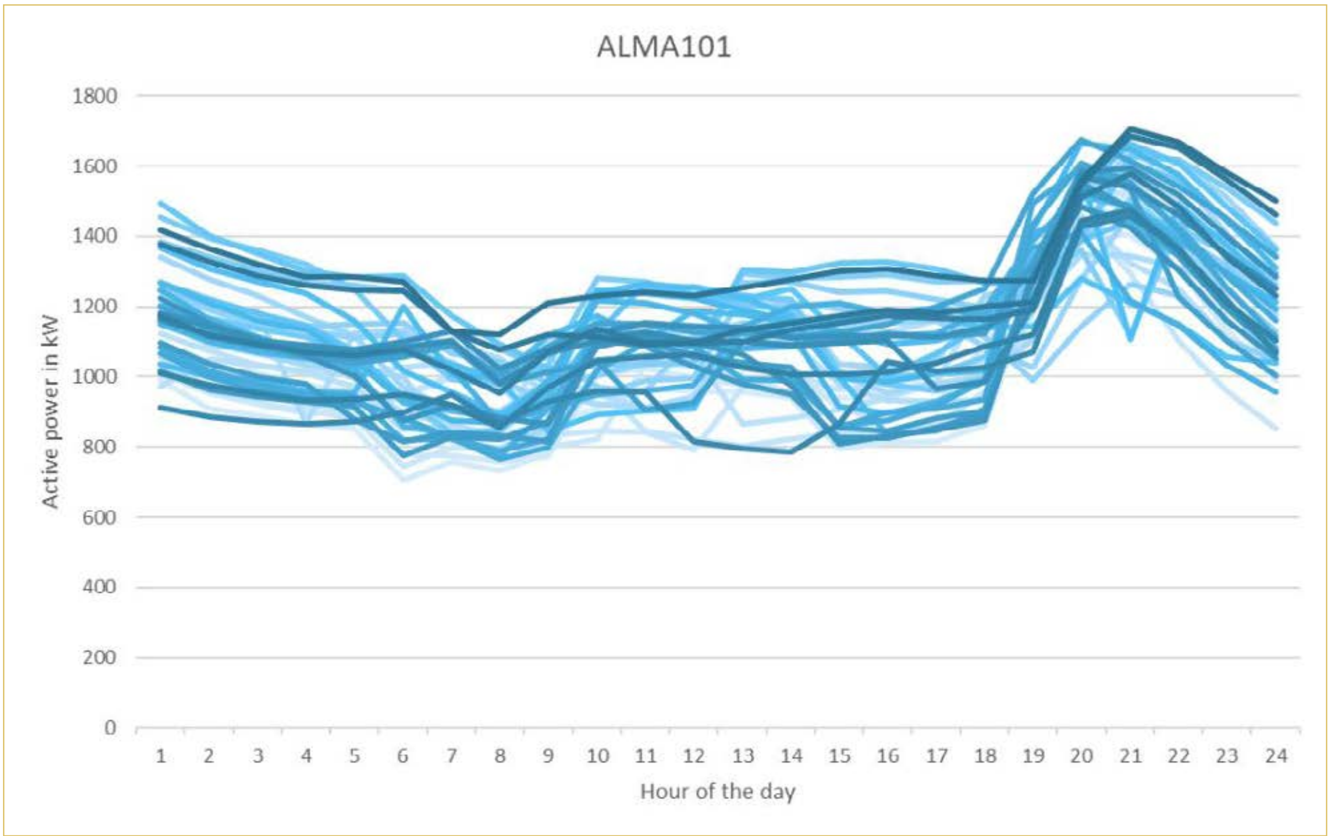
Figure 14 shows the load development for the feeder ALMA101 over a time period of 1.25 years. The darker the colour, the later the time of the respective daily load curve. As can be observed, there is a moderate load growth over the analysed time period. Furthermore, the demand is relatively constant throughout the day, with typically a small peak in the evening time. Minimum demand typically occurs during the day and coincides with PV production. This verifies the approach to select the minimum demand in combination with the maximum PV production, which represents the worst-case scenario. On some feeders, however, load curtailing is performed during daytime, leading to a reduced minimum daytime demand. In this case, this was not taken into account, leading to a conservative (smaller) estimate of the minimum demand, i.e. the simulated impact from PV generation will be more severe.

6.6.2 PV impact on the daily load curve

Most feeders in the Dominican Republic have still very low PV penetration levels. Therefore, the impact on most feeders is difficult to see. In the case of EdeNorte, some feeders have already PV penetration levels above 25% and even up to more than 100%. One such case is presented in Figure 15. The feeder VOLG101 has a PV penetration level of ca. 27%. As can be seen, the PV penetration reduces the minimum load but does not lead to any reverse power flows at the moment.

In this study, due to the still low PV penetration levels, the current PV impact on the minimum load was however not considered. This leads in fact to a conservative or worst-case estimation of the PV impact: Considering these PV plants would

Figure 14: Trend of the daily load curve over the course of 1.25 years for the feeder ALMA101



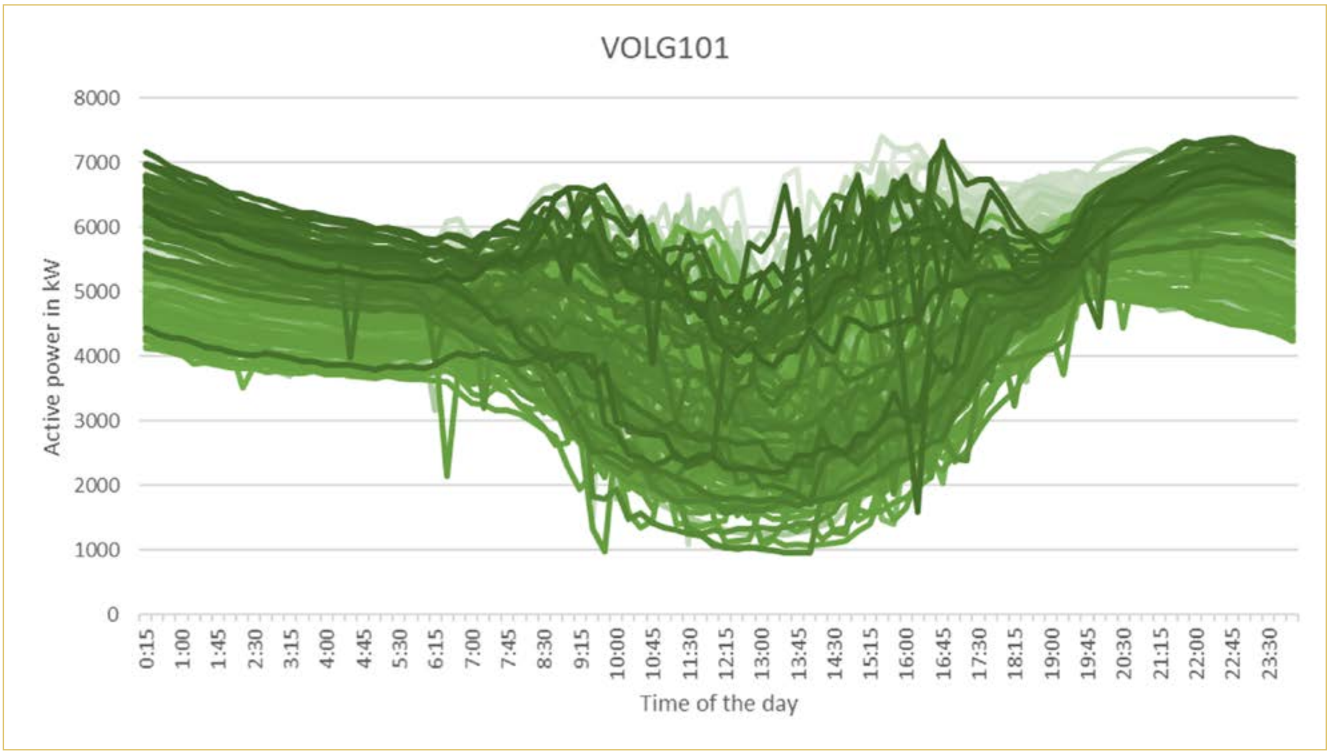
mean to increase the minimum load, as the current minimum demand may be already lowered by the existing PV. A higher minimum load in turn means a higher possible PV penetration level. However, due to insufficient data on the distribution of existing PV within the feeders this impact was disregarded.

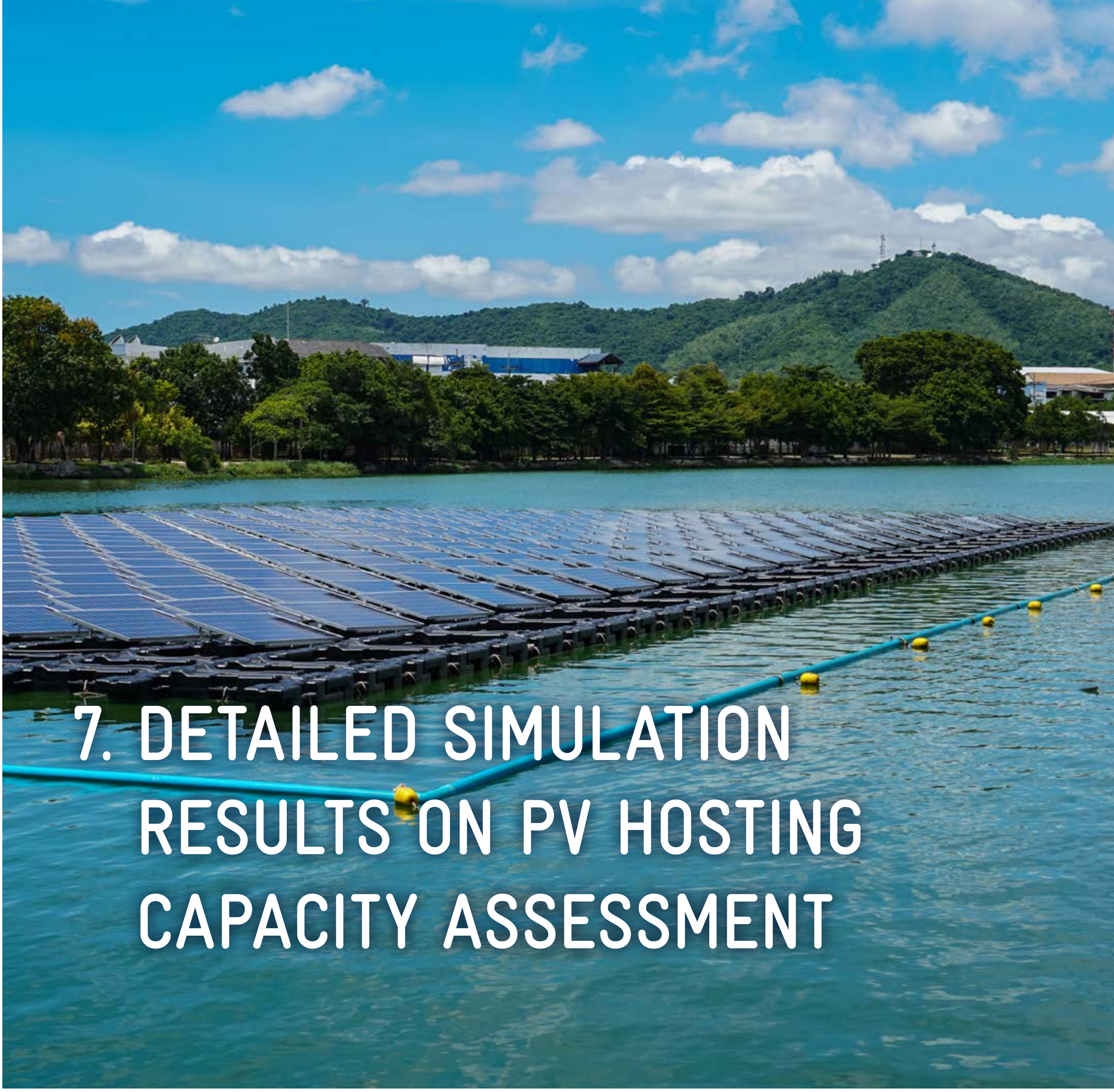
6.6.3 Phase imbalances

Further measurement data was obtained for the analysed feeders with regard to the current flow across each phase. These indicated that the loads in the distribution feeders are evenly distributed across the different phases. The largest phase imbalance was observed on the DAJA104 feeder with an unbalance of 31% / 36% / 33% during peak load.

Therefore, in the simulations, an even distribution of load across all three phases was assumed.

Figure 15: Trend of the daily load curve over the course of 1.25 years for the feeder VOLG101 which already has a 27% PV penetration which is seen on the reduction of daytime demand.





7. DETAILED SIMULATION RESULTS ON PV HOSTING CAPACITY ASSESSMENT

In the following chapter, some selected feeders are chosen to describe the models in detail and the impact of PV on these selected feeders. The selected feeders show different types of feeders and which typical issues and situations may arise with increasing PV penetration levels.

7.1 ALMA101 (EdeNorte)

Figure 16 shows the detailed geographic single line diagram of the feeder. Indicated by the colours are the different phases of single- and three-phase lines as well as the HV/MV substation indicated by the black circle. As can be seen, the feeder consists of mostly single-phase lines, branching off in different directions.

Figure 16: Geographic single line diagram of ALMA101

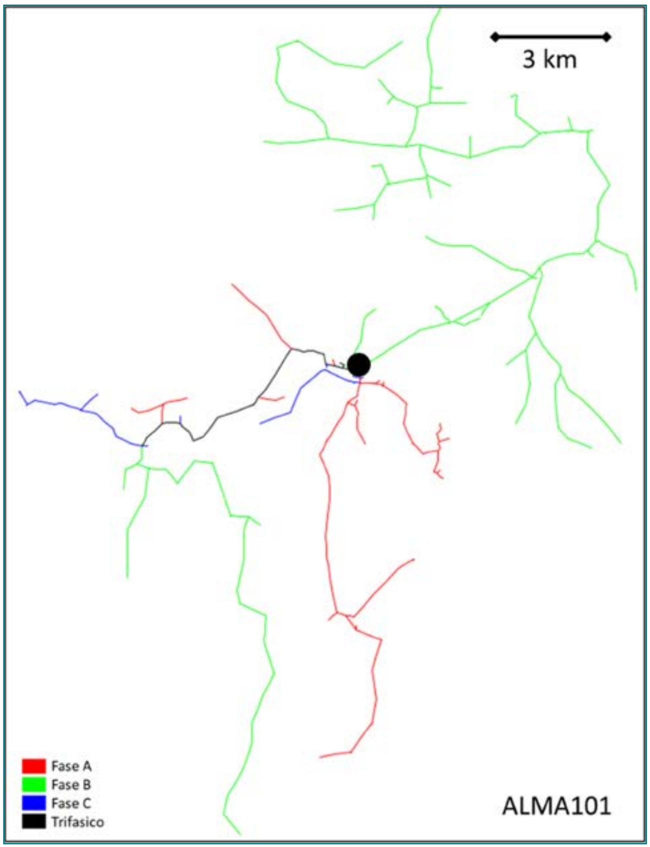
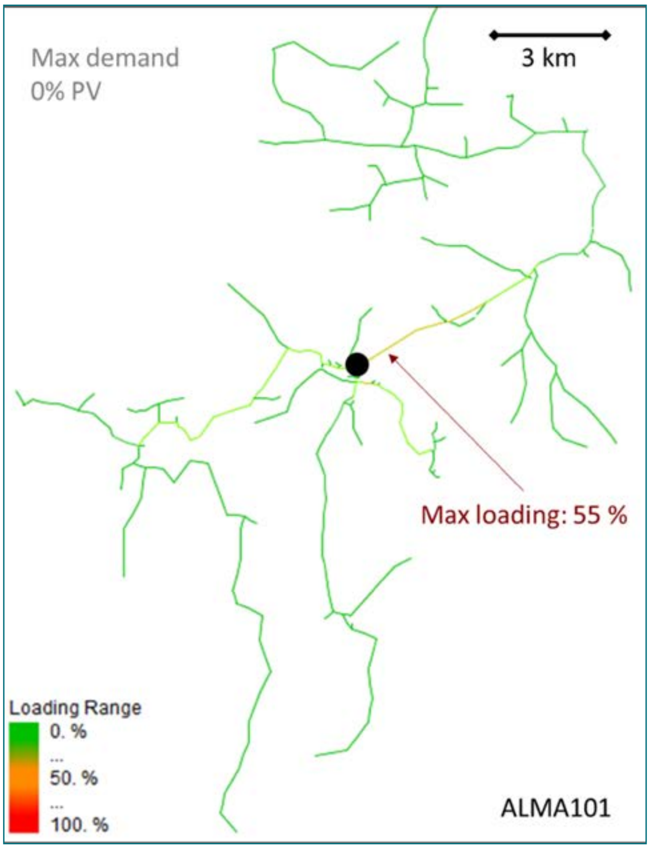


Figure 17: Line loadings during peak demand for ALMA101



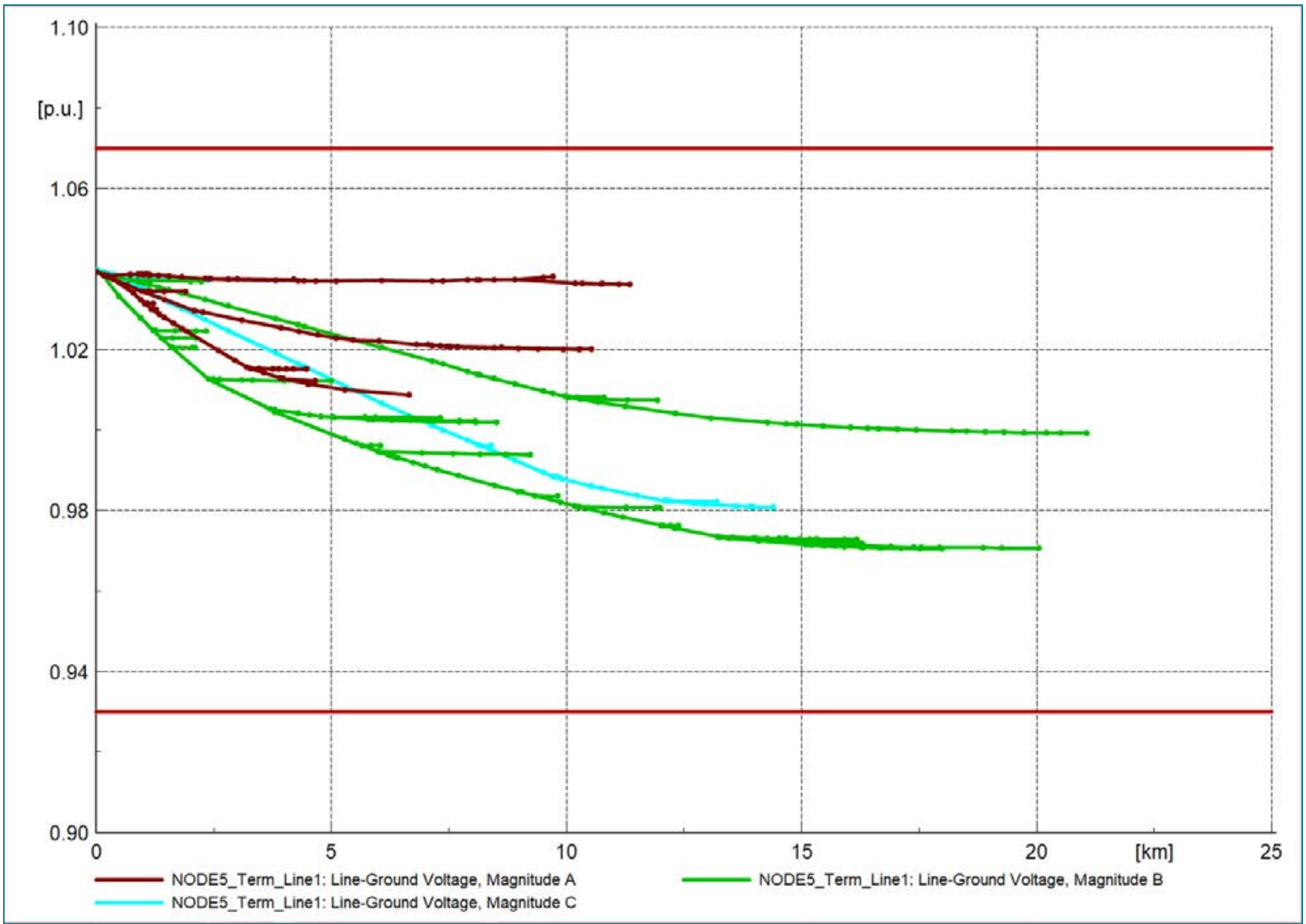
7.1.1 Feeder behaviour during peak demand without PV

During peak demand the feeder exhibits low line loadings, as can be seen in Figure 17. Most lines are loaded below 30%, with the maximum loading occuring on the feeder branch leading east with 55% line loading.

Figure 18 shows the voltage profile of the feeder during peak demand. Indicated on the x-axis is the distance from the primary substation, while the y-axis shows the voltage level. The different colors represent the three phases of the feeder. The voltage set-point for the primary substation has been chosen to be 1.04 p.u. As can be observed, the voltage drops by 7% to approximately 0.97 p.u. on phase B. On this phase the longest branches are located, with distances of more than 20 km from the substation.

Indicated by the red lines at 1.07 p.u. and 0.93 p.u. are the voltage limitations as defined for the medium voltage grid. This allows for an additional voltage drop or voltage rise in the low voltage network, in order to keep the voltage levels of 0.9 p.u. to 1.1 p.u. at the customers' premises.

Figure 18: Voltage profile during peak demand without PV for ALMA101



In summary, the following characteristics can be observed for the ALMA101 feeder:

- Long single-phase lines
- Large share of 1-phase loads
- Phase B network part considerably longer than other phases
- Up to 21 km feeder distance from the primary substation
- Simulated voltage drop of 7% during peak demand
- Simulated maximum loading of 55%
- Peak demand of 1.8 MVA, minimum demand of 0.8 MVA (43%)

7.1.2 Feeder behaviour during minimum demand with increasing PV penetration

With increasing PV penetration levels, the downstream power flow is reduced up to the point where reverse power flow occurs and power is exported from the feeder branch to the other feeder branches or to the upstream network. The reverse power flows are leading to a voltage increase across the feeder, as opposed to the typical voltage drop when load is greater than PV injection. Furthermore, if PV penetration is high enough or concentrated on few locations, it may lead to the overloading of lines.

Figure 19 shows the impact of a gradual increase in PV penetration on the ALMA101 feeder, considering a uniform distribution of PV plants across the feeders, as described in chapter 5.1. During minimum demand, the voltage drop is considerably lower compared to the situation during peak demand. If PV penetration during the time of minimum demand, the feeder voltage is further increased.

At a PV penetration level of 15%, however, the voltage is still dropping across the feeder length, as the minimum load with 43% of peak demand still exceeds PV production. At a PV penetration level of 60%, there are slight reverse power flows and the resulting voltage drop is relatively flat. The upper voltage limitation of 1.07 p.u. (leaving 3% voltage increase for the LV network) is only reached at a PV penetration level of approximately 135%. The feeder was analysed up to a PV penetration level of 150%. In this case, the resulting voltage increase is about 4% or 1.08 p.u. and may lead to overvoltages above 1.10 p.u. in the LV network. Hence, such a PV penetration level would only be possible by applying mitigation measures, that are described in chapter 9.

Figure 19: Voltage profile with increasing PV penetration level for ALMA101, uniform PV distribution

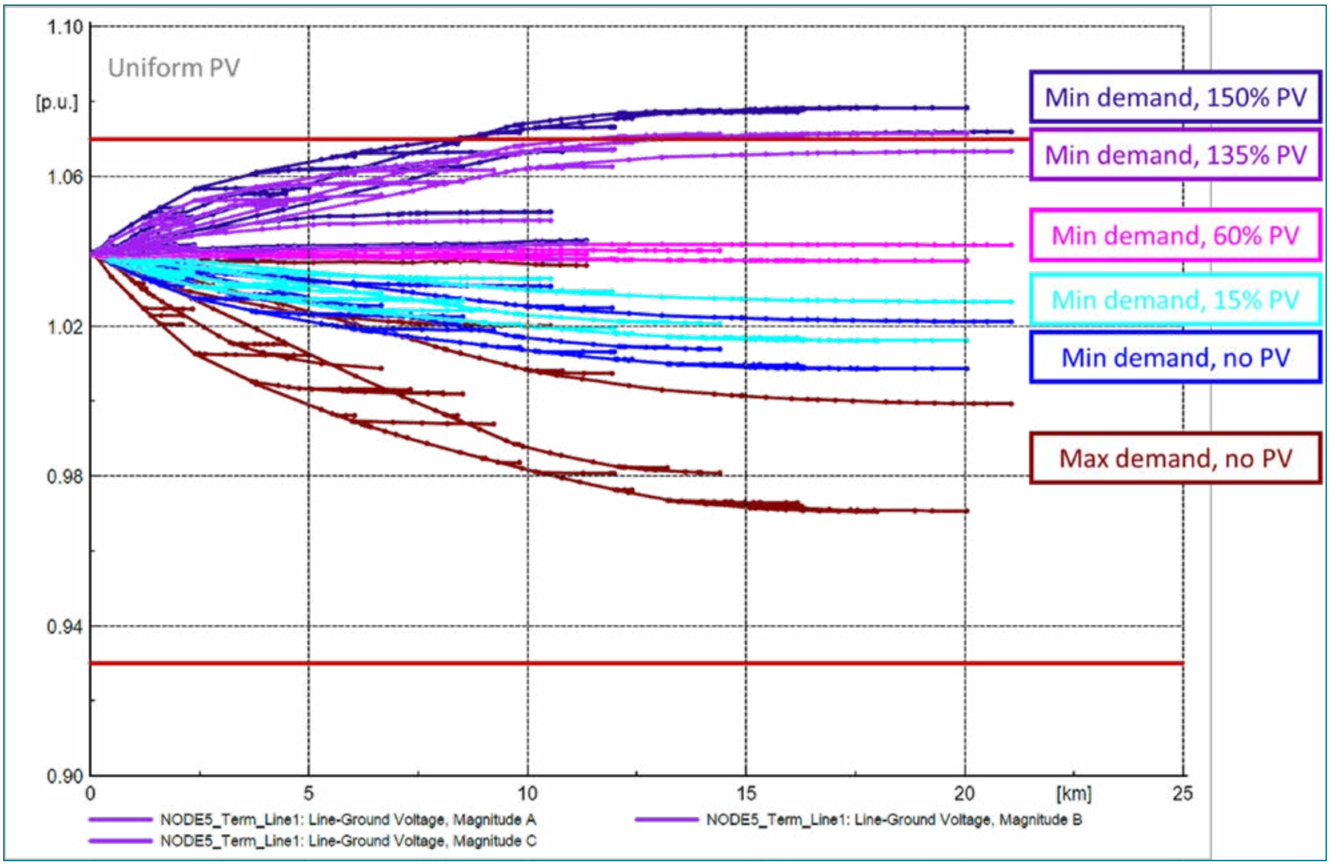


Figure 20 shows the voltage profile for an uneven PV distribution across the feeder. In this case, the majority of PV plants is connected to the end of the feeder, as described in chapter 5.1.

Voltage profiles of maximum and minimum demand are equal to Figure 19, as no PV is added. As can be observed, in this case only a maximum PV penetration of approximately 75% can be added to the feeder, before the voltage limit of 1.07 p.u. is breached. The uneven distribution of PV plants leads to one of the branches having considerably more PV plants than the other feeder, hence resulting in a large voltage increase on that branch. In the case of a uniform PV distribution, this voltage unbalance is not observed. A PV penetration of 150% would lead to a voltage violation on all three phases, with one of the phases showing voltage levels up to 1.13 p.u. (outside of scope on Figure 20).

Figure 20: Voltage profile with increasing PV penetration level for ALMA101, uneven PV distribution

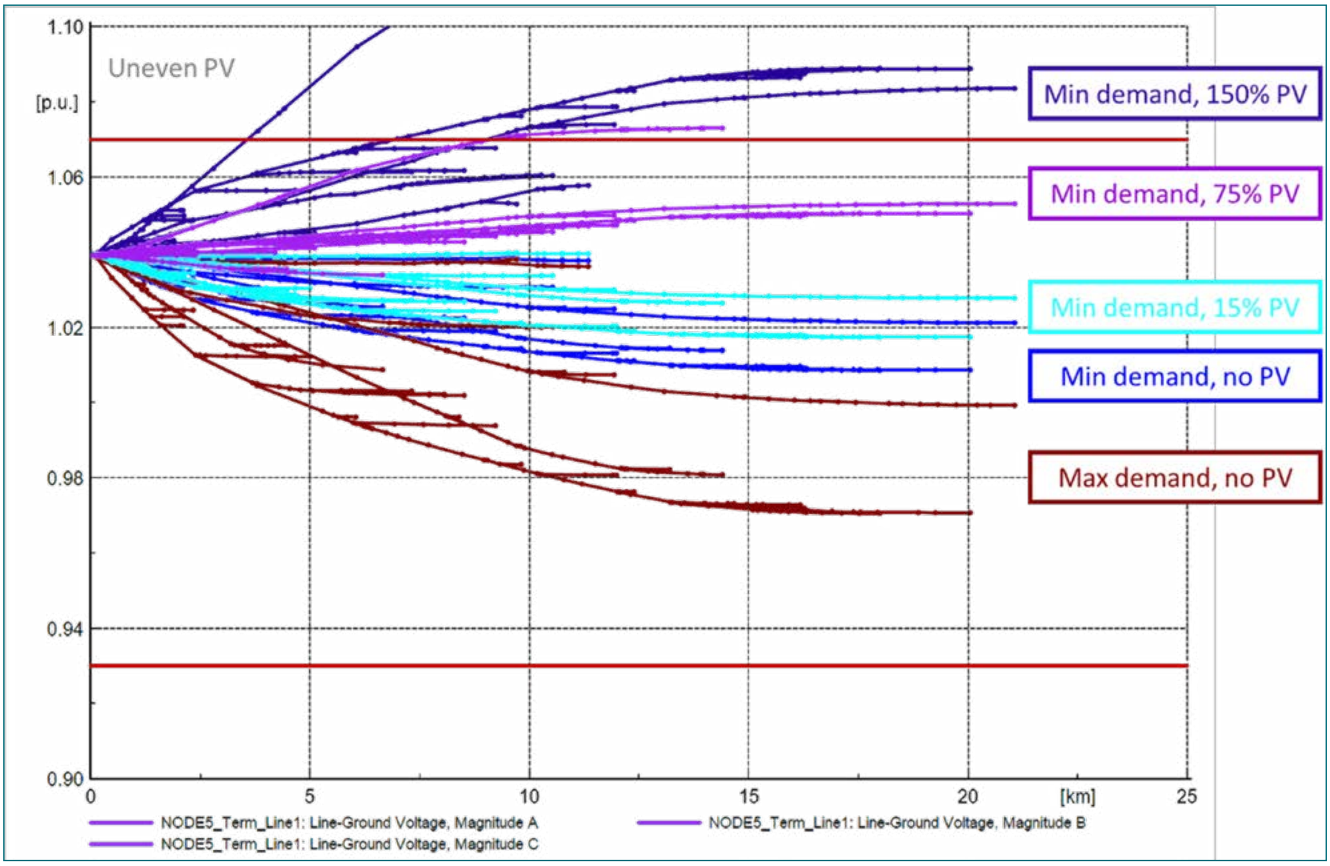
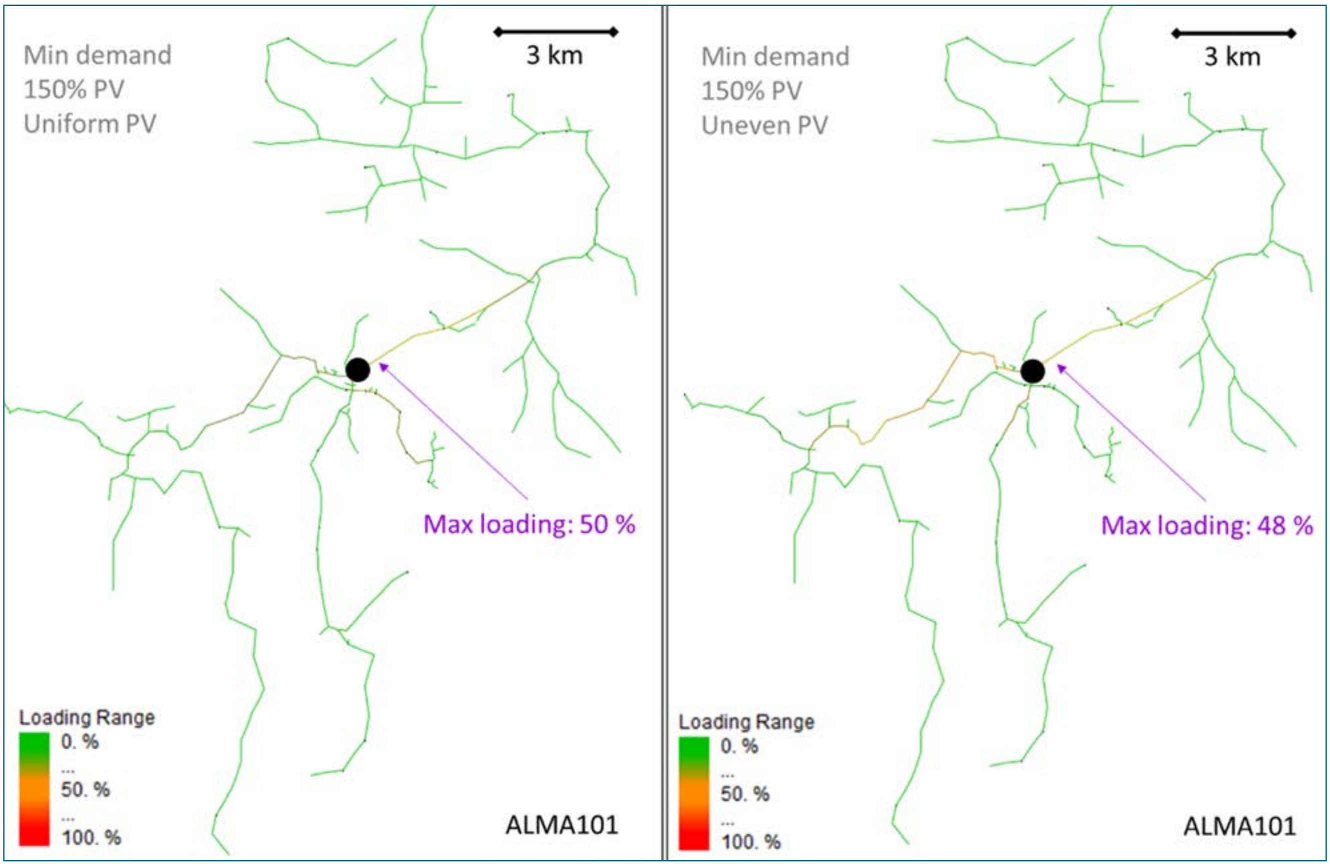


Figure 21 shows the feeder coloured by the loading level for both the uniform as well as the uneven PV distribution scenario for a 150% PV penetration level scenario. In both cases, the maximum loading observed on the lines is approximately 50%, which is in fact lower than the maximum loading during peak demand. Hence, the line loading does not pose a restriction for the PV penetration.

In summary, the following can be observed:

- No violation of line loadings even at 150% PV penetration levels
- Maximum PV penetration level of 135% (uniform PV distribution) or 75% (uneven PV distribution) before voltage thresholds are violated

Figure 21: Maximum line loadings during 150% PV for ALMA101. Left: Uniform PV distribution, right: uneven PV distribution



7.2 HAMY01 (EdeEste)

Figure 22 shows the geographic single line diagram for the feeder HAMY01. Located close to the primary substation is the small town Hato Mayor del Rey, with multiple very long, mostly single-phase branches leading to further villages in the countryside.

7.2.1 Feeder behaviour during peak demand without PV

This feeder exhibits very high loading levels during peak demand. According to the obtained information from EdeEste, a large share of lines is already overloaded, with some lines close to the substation being overloaded by up to 250%.

Figure 22: Geographic single line diagram of HAMY01

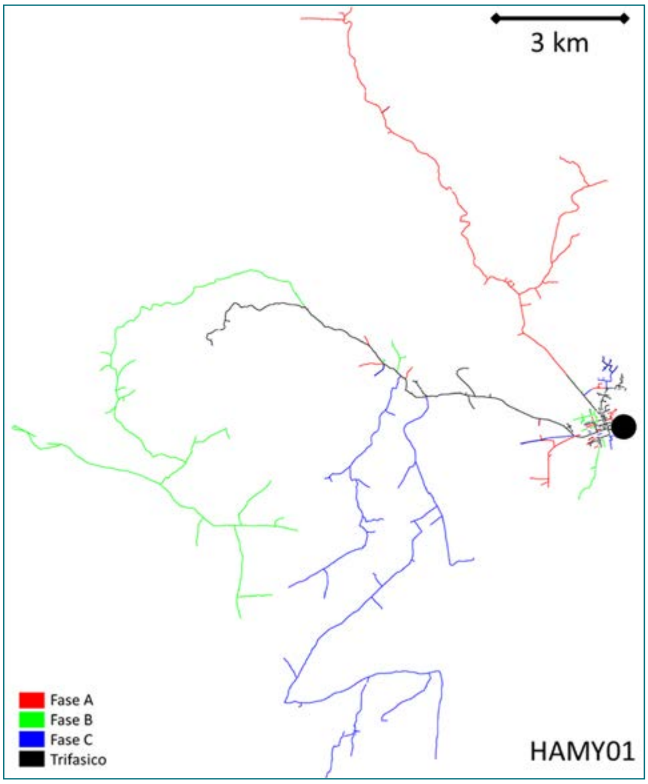
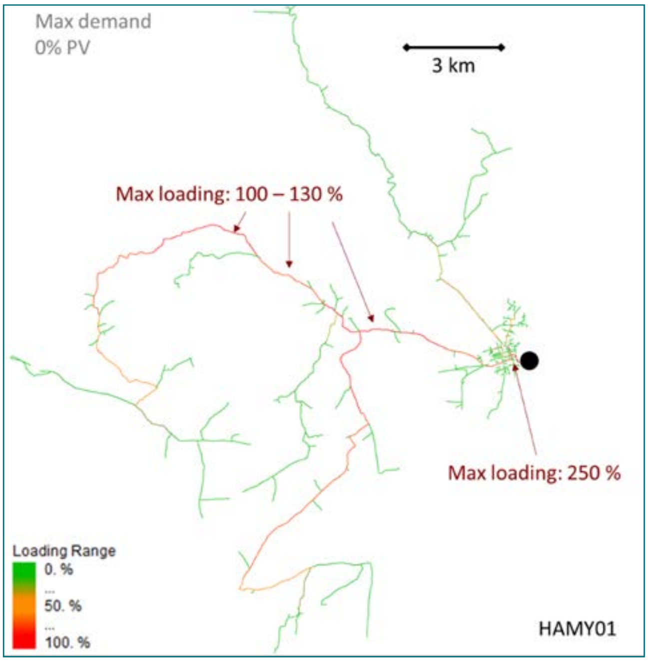


Figure 23: Line loadings during peak demand for HAMY01

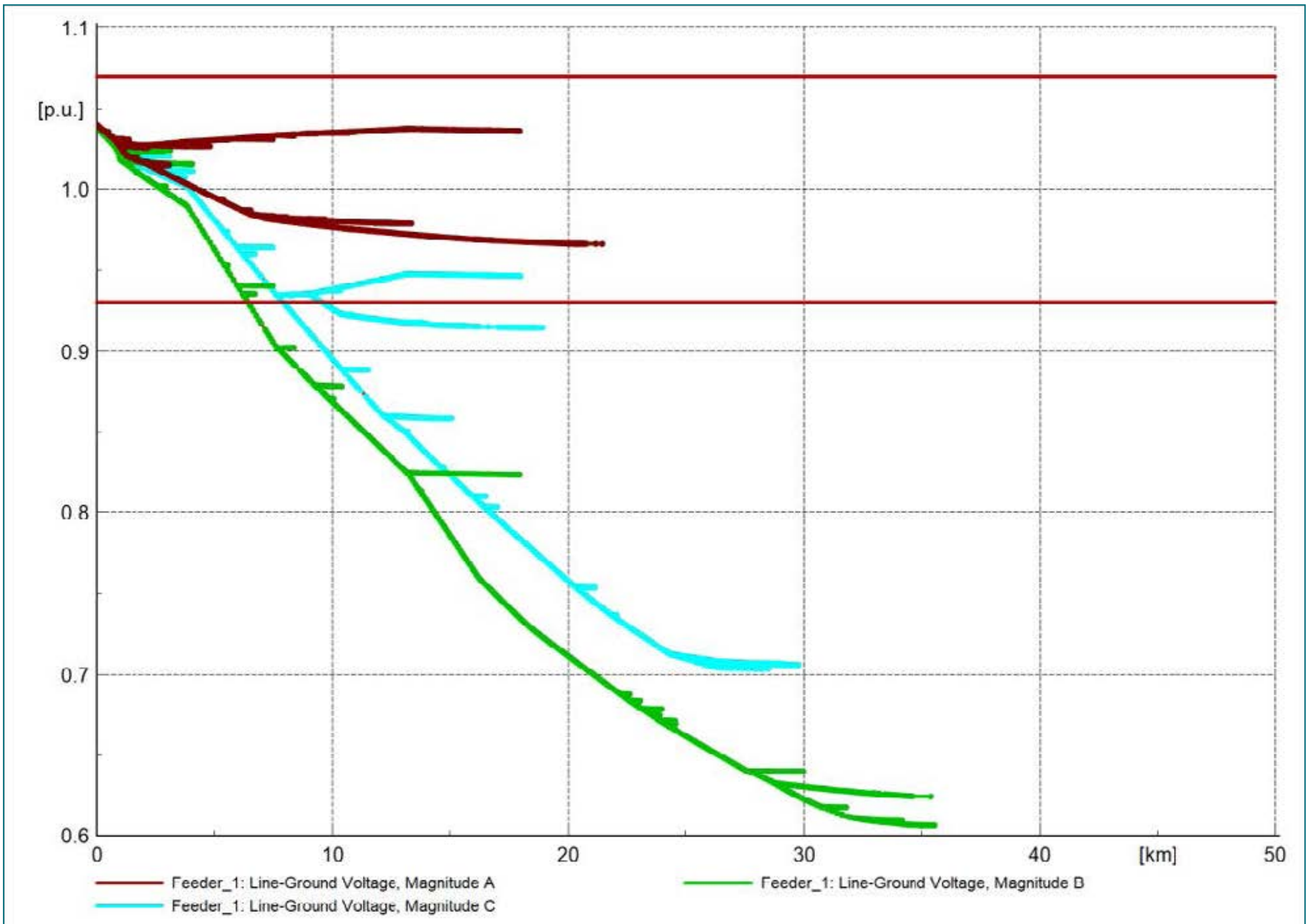


Long line lengths in combination with the high loading of the lines result in a large voltage drop across the feeder, as can be seen in Figure 24. Simulated voltage levels are as low as 0.6 p.u. in the rural areas. Such low voltage levels were also reported by the DSOs. However, further measurement data would be needed to verify such low voltage levels which is currently not available. Therefore, the obtained simulation results must be treated with care and voltage levels could be significantly higher or lower. Some adaptions to the current model were already taken, by assuming that rural distribution transformers are on average 20% less loaded compared to distribution transformers in the city. A higher difference between rural and urban areas would result in less load in the rural areas and hence a smaller voltage drop.

In summary, the following characteristics can be observed for the HAMY01 feeder:

- Long single-phase lines
- Large share of 1-phase loads
- Phase B network part considerably longer than other phases

Figure 24: Voltage profile during peak demand without PV for HAMY01



- Up to 36 km feeder distance from the primary substation
- Simulated voltage drop down to 0.6 p.u. during peak demand
- Simulated maximum loading up to 250%
- Peak demand of 7.9 MVA, minimum demand assumed to be 20% due to insufficient data (1.6 MVA)

7.2.2 Feeder behaviour during minimum demand with increasing PV penetration

Since the feeder shows very high voltage drops during peak demand, it is also more sensitive towards increases in the PV penetration level. Figure 25 shows the voltage profile with increasing PV penetration levels for the uniform PV penetration scenario. Up to a PV penetration level of 30% the voltage thresholds are not violated. At a PV penetration level of 45%, however, the voltage level increases just above 1.07 p.u.

Figure 25: Voltage profile with increasing PV penetration level for HAMY01, uniform PV distribution

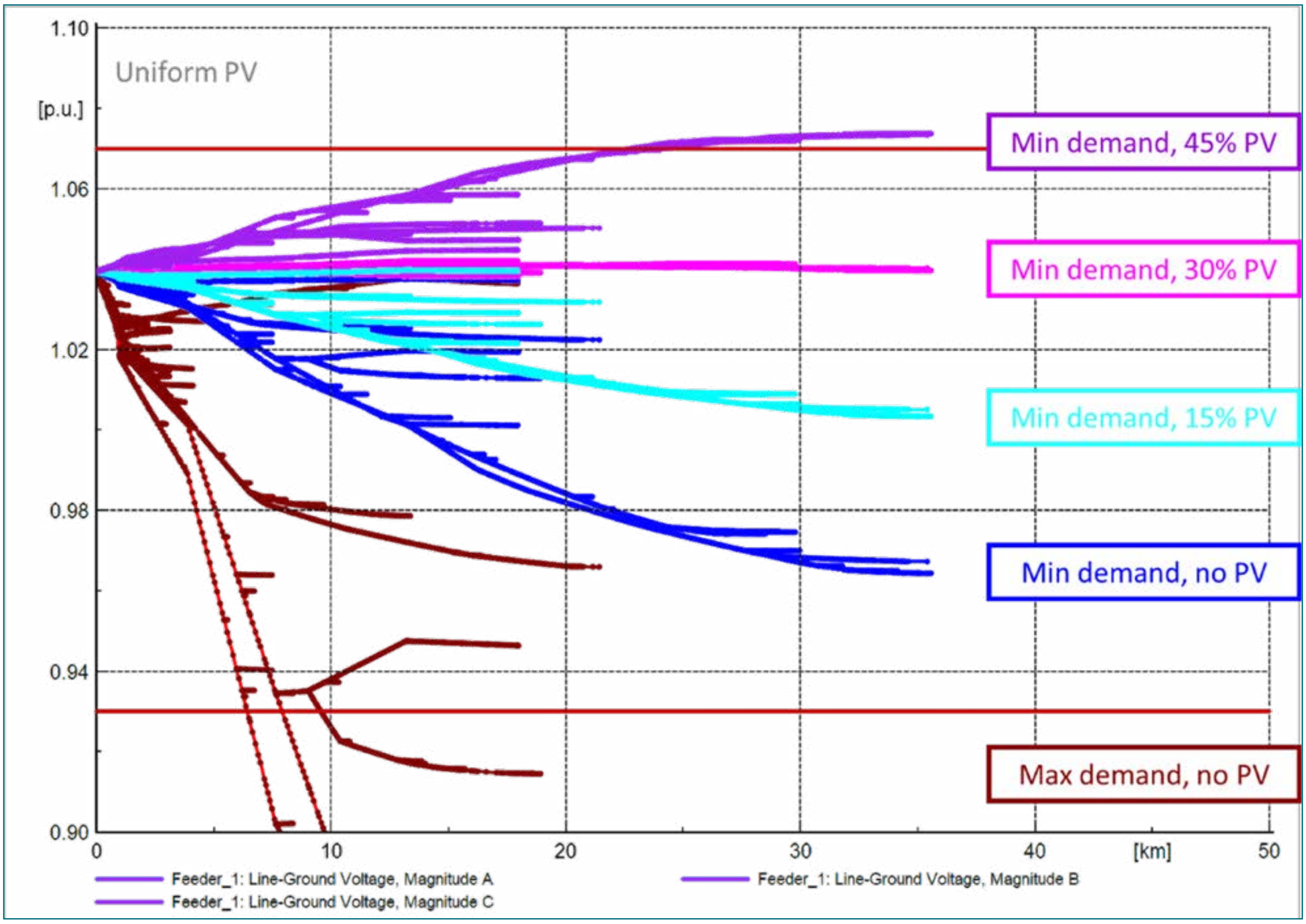


Figure 26 shows the voltage profiles during uneven PV penetration. The uneven distribution leads to a majority of PV plants connected to the end of the lines in the rural areas. In this case, the maximum PV penetration level is only somewhat above 15% and voltage violations occur already at 30% PV penetration. The likelihood of such a scenario may however be lower, as PV plants are more likely to be installed by people living in the city due to higher purchasing power. Hence, PV penetration levels in this case are severely impacted by the distribution of PV power plants and may be considerably higher.

Finally, Figure 27 shows the line loadings for the feeder for a uniform PV penetration of 45%. As can be seen, the PV compensates the loads and leads to very low line loadings.

Figure 26: Voltage profile with increasing PV penetration level for HAMY01, uneven PV distribution

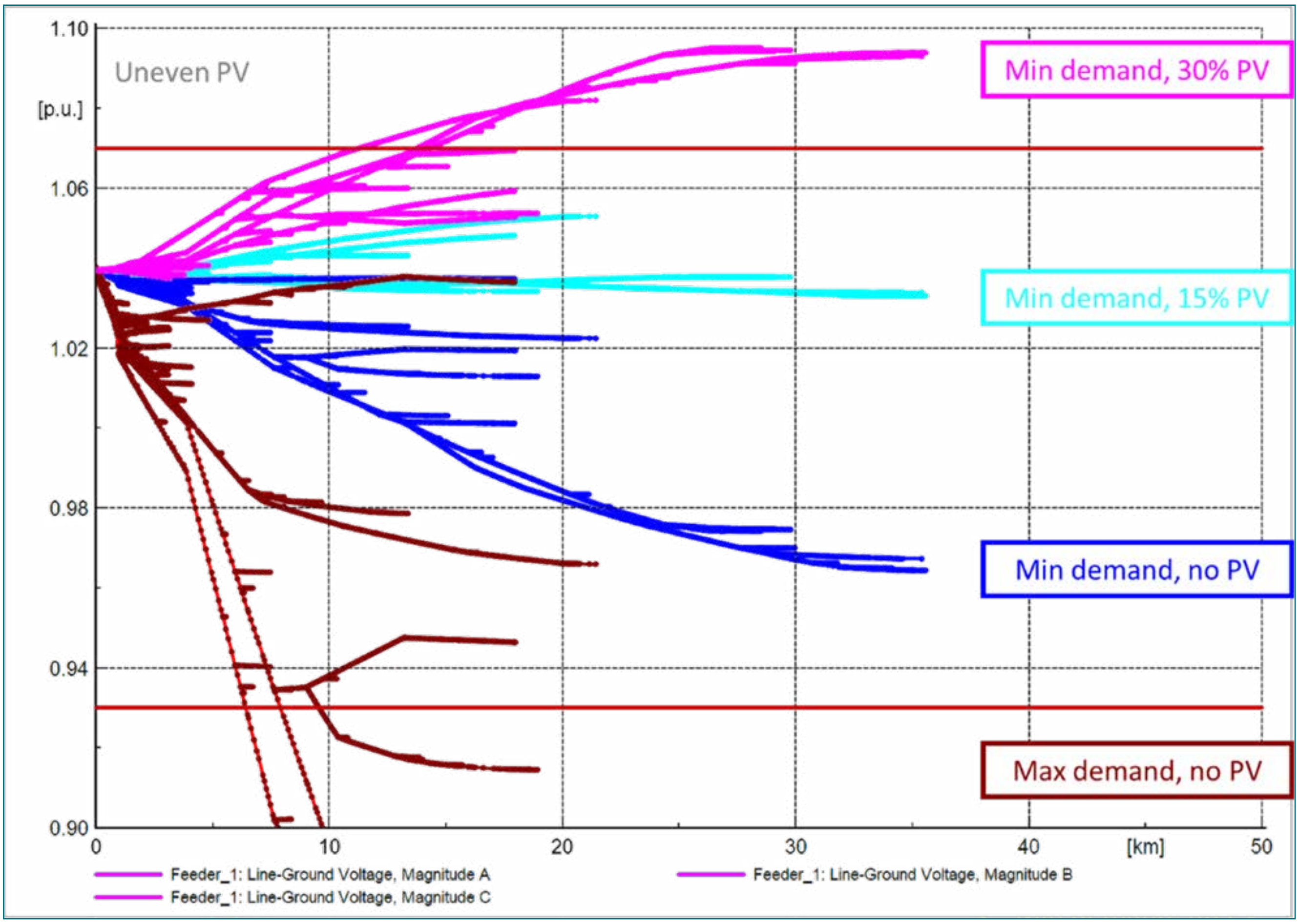
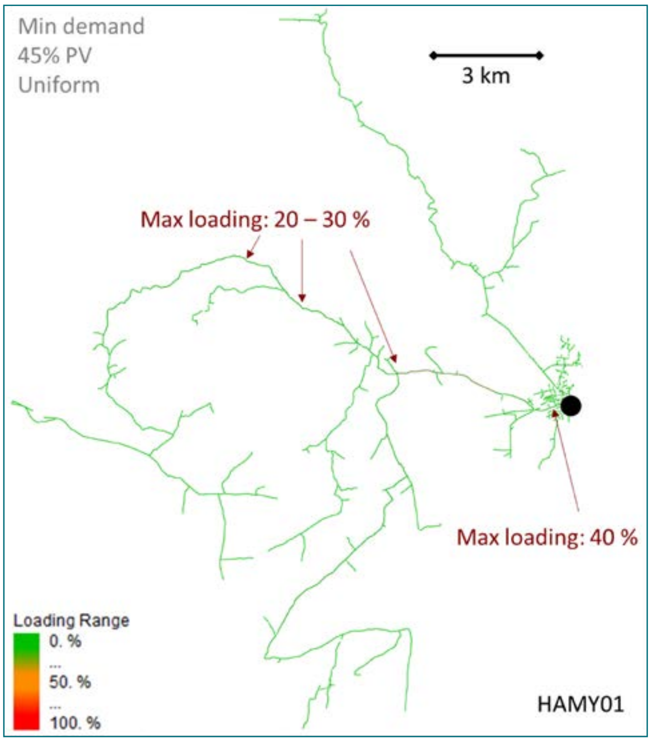


Figure 27: Maximum line loading during 45% PV for ALMA101, uniform PV distribution



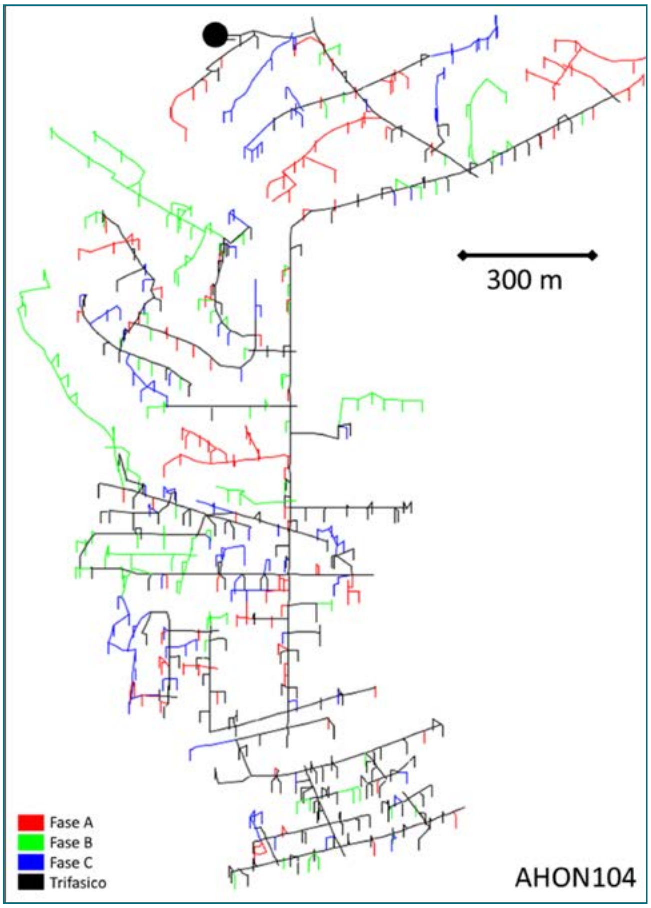
In summary, the following can be observed:

- PV penetration levels are severely limited by voltage increases due to PV infeed
- Considering a uniform PV distribution, the PV penetration is close to 45%
- Considering an uneven PV distribution, the PV penetration is approximately 15% to 30%
- At these PV penetration levels, line loading levels are very low, as demand is locally served by the PV production
- The locational distribution of PV plants has a high impact on the PV penetration level

7.3 AHON104 (EdeSur)

Figure 28 shows the geographic single line diagram of the feeder AHON104. This feeder has, contrary to the previous two examples, much shorter line lengths and only short single-phase branches, with the trunk conductor being a three-phase conductor. This is a more typical feeder configuration located in the urban areas of major cities. This particular feeder is located in Santo Domingo.

Figure 28: Geographic single line diagram of AHON104

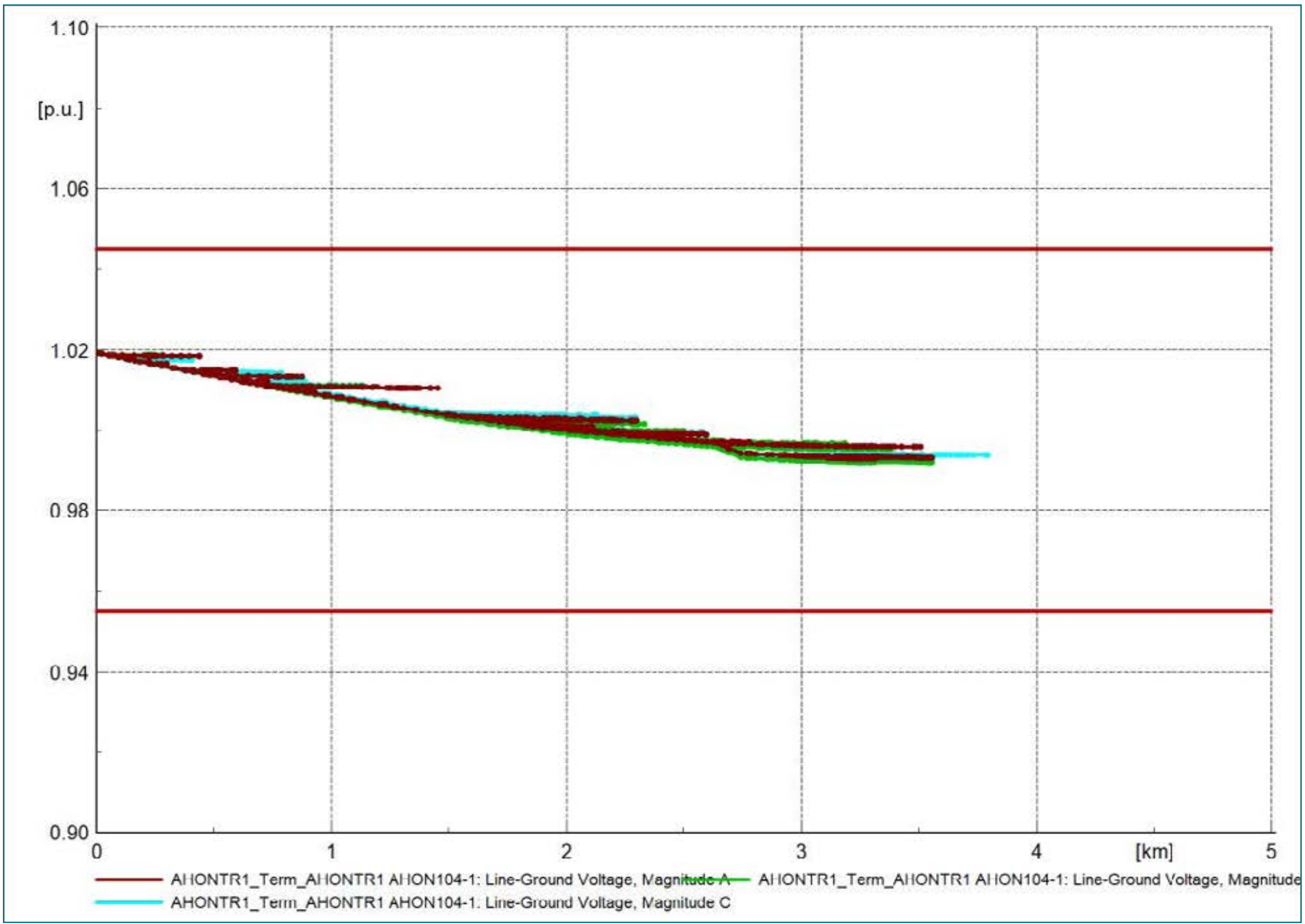


7.3.1 Feeder behaviour during peak demand without PV

For urban feeders, a stricter voltage range from 0.925 p.u. to 1.075 p.u. applies. Considering also here an additional voltage range of 3% for the low voltage network, this leaves a voltage range for the medium voltage network of 0.955 p.u. to 1.045 p.u. (± 4.5%) as indicated by the red thresholds in Figure 29. As can be seen, the short feeder length leads only to a minor voltage drop during peak demand. Furthermore, there exist almost no voltage unbalances.

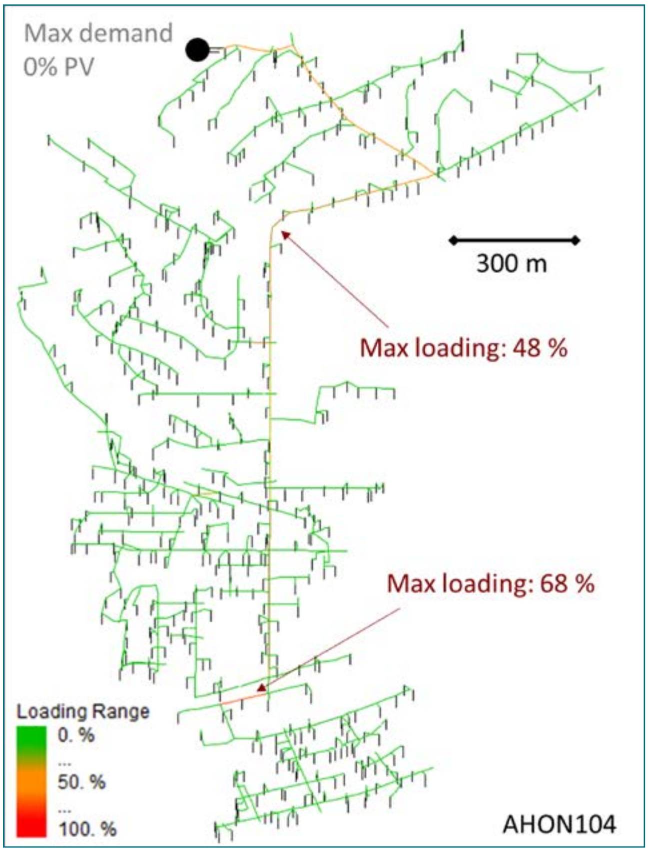
The voltage setpoint for the transformer is typically lower compared to rural areas and has been set to 1.02 p.u.

Figure 29: Voltage profile during peak demand without PV for ALMA104



Line loadings in comparison to that are moderate, with values as high as 68% on the trunk line, as can be seen in Figure 30.

Figure 30: Line loadings during peak demand for ALMA104



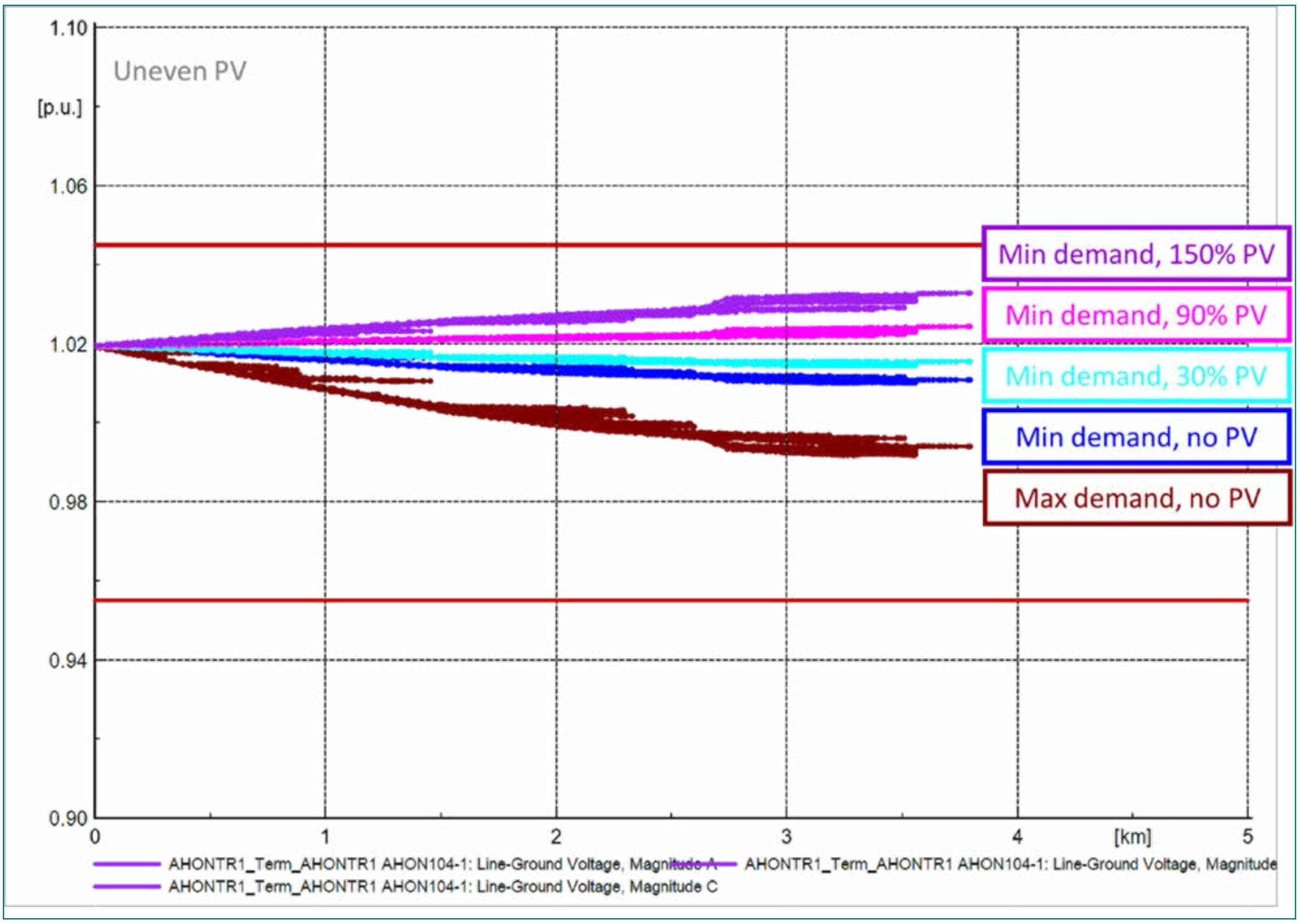
The following characteristics can be summarized for this feeder:

- Mostly three-phase lines with only short single-phase lines
- Approximately two thirds of transformer are connected 3-phase
- Only up to 4 km feeder distance from the primary sub-station
- Simulated voltage drop of ca. 3% during peak demand
- Simulated maximum loading up to 68%
- Peak demand of 7.1 MVA, minimum demand of 2.5 MVA (35%)

7.3.2 Feeder behaviour during minimum demand with increasing PV penetration

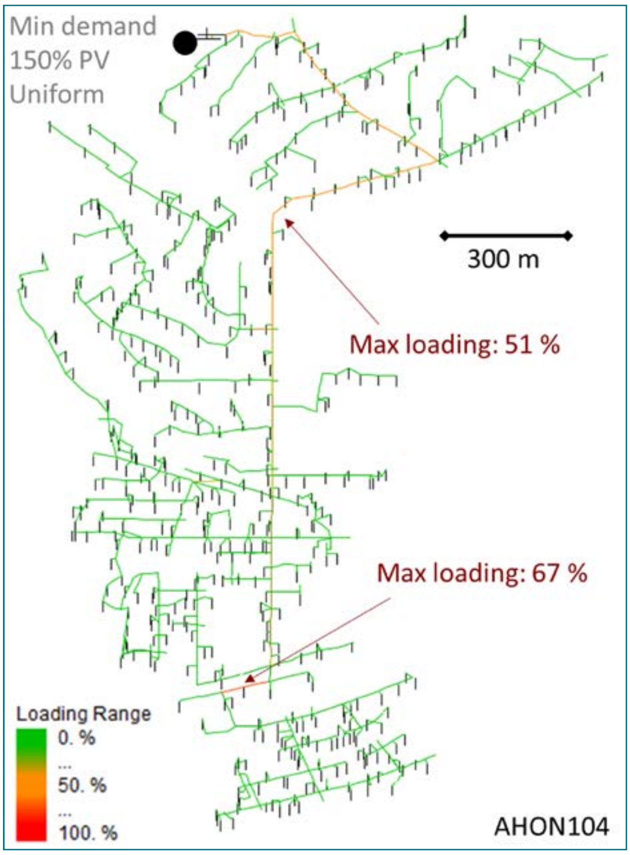
Increasing PV penetration levels have a much smaller impact on the voltage as the lines have larger cross-sections compared to rural areas and are very short. As can be seen in Figure 31, even increasing PV penetration levels up to 150% still does not violate the upper voltage threshold of 1.045 p.u., despite an uneven PV distribution. The uniform PV distribution shows even less voltage deviation (not depicted).

Figure 31: Voltage profile with increasing PV penetration level for AHON104, uneven PV distribution



Also, line loadings are kept within their applicable limits, as seen in Figure 32. Maximum line loadings are in the same order of magnitude as during peak demand and no significant problems are expected.

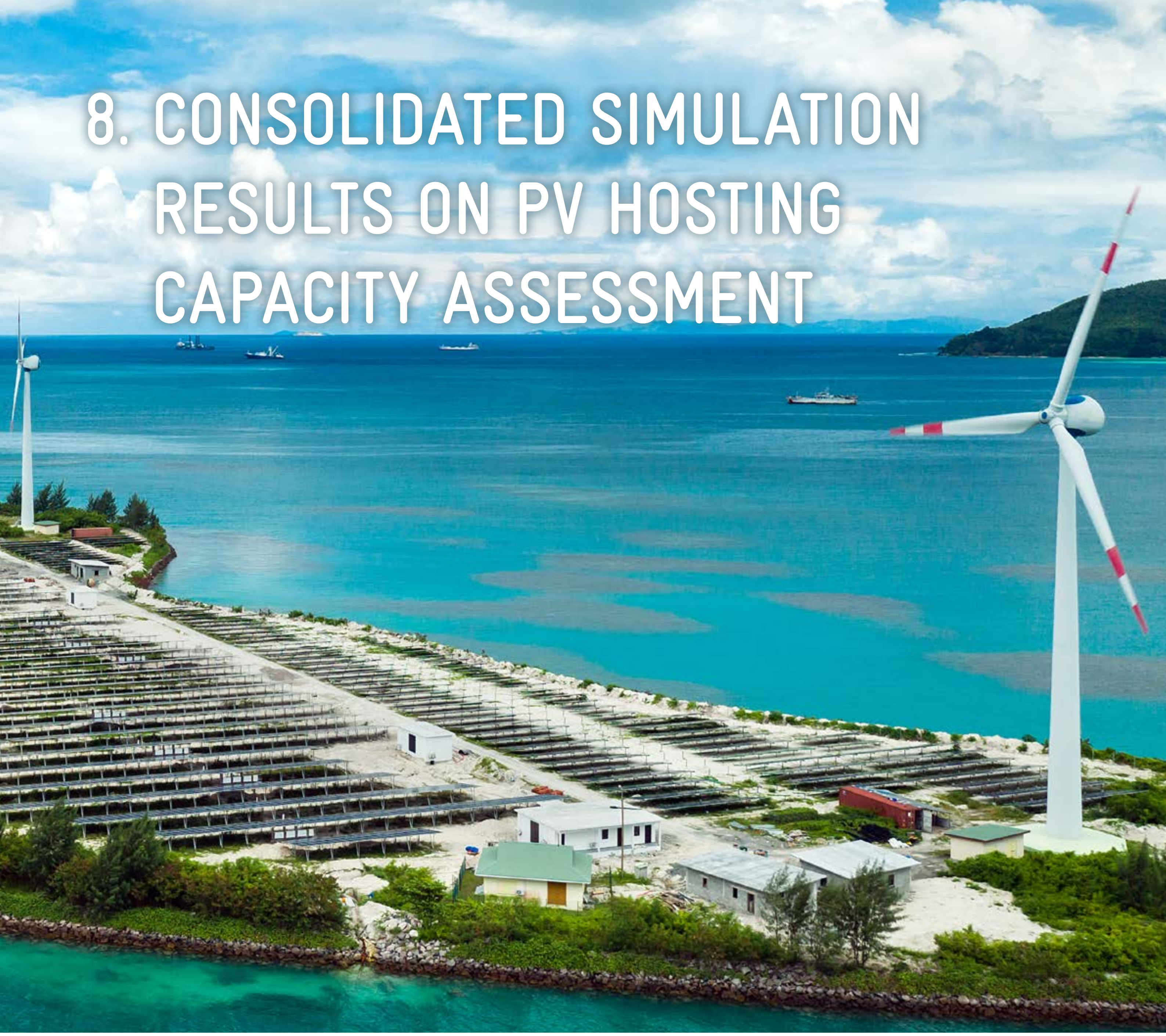
Figure 32: Maximum line loading during 150% PV for AHON104, uneven PV distribution



In summary, the following can be stated:

- Neither voltage violations nor line loadings present a limitation for PV penetration levels up to 150%. Hence, PV power plants in such a MV feeder could be installed even above a level of 150%.

8. CONSOLIDATED SIMULATION RESULTS ON PV HOSTING CAPACITY ASSESSMENT

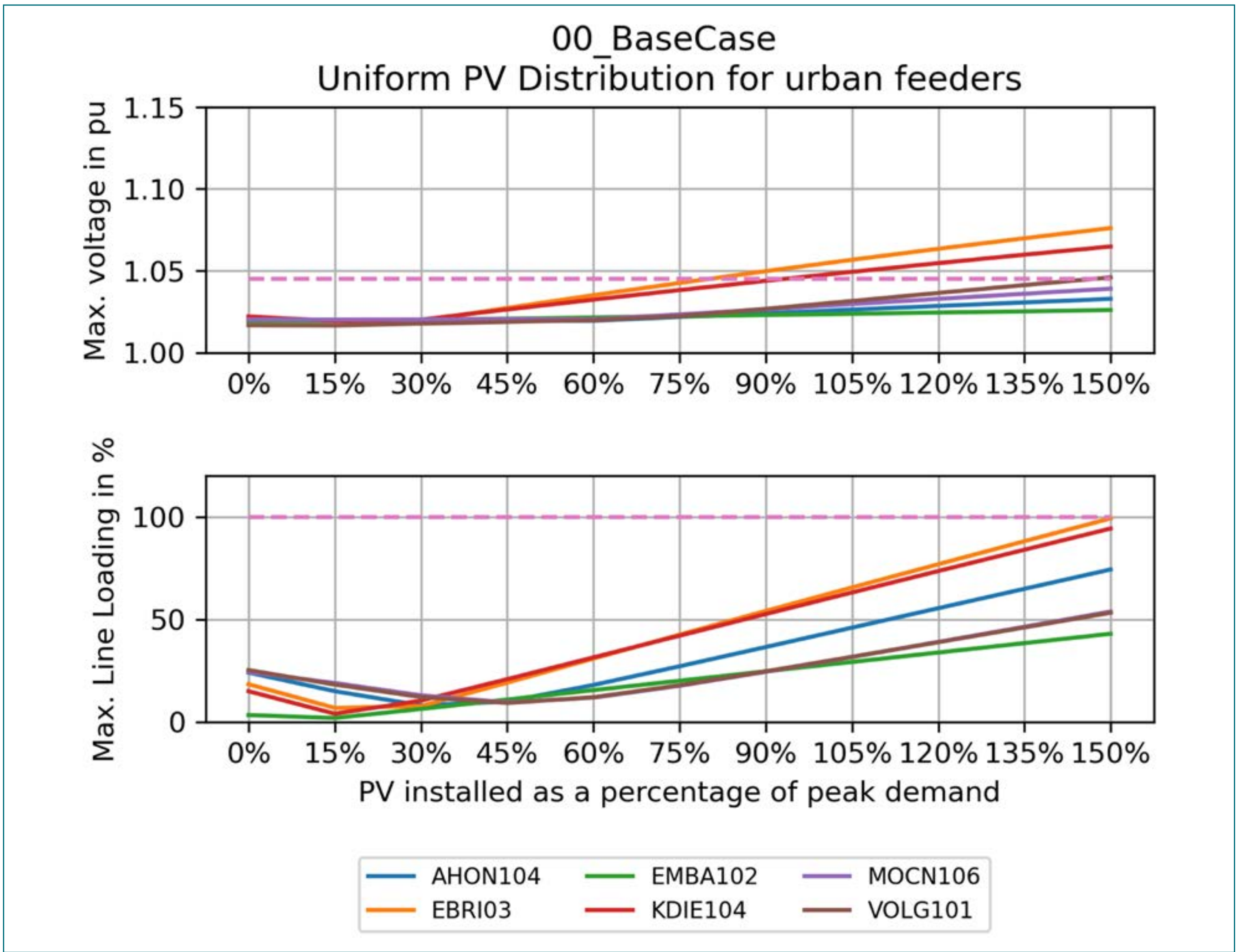


The following figures show the consolidated results of the impact on line loadings and voltage levels for PV penetration levels up to 150%. The depiction has been divided into urban and rural feeders, as different voltage thresholds apply and different voltage setpoints for the transformer have been chosen, following current DSO practices and analysed measurement data.

8.1 URBAN FEEDERS

Figure 33 shows the results for the uniform PV distribution. As can be seen, the voltage threshold of 1.045 p.u. is only reached by two of the five feeders. For these two feeders, EBRI03 and KDIE104, PV penetration levels up to 80% and 90% respectively are possible. Line loading violations do not occur in any of these feeders. In fact, low PV penetration levels first relieve the

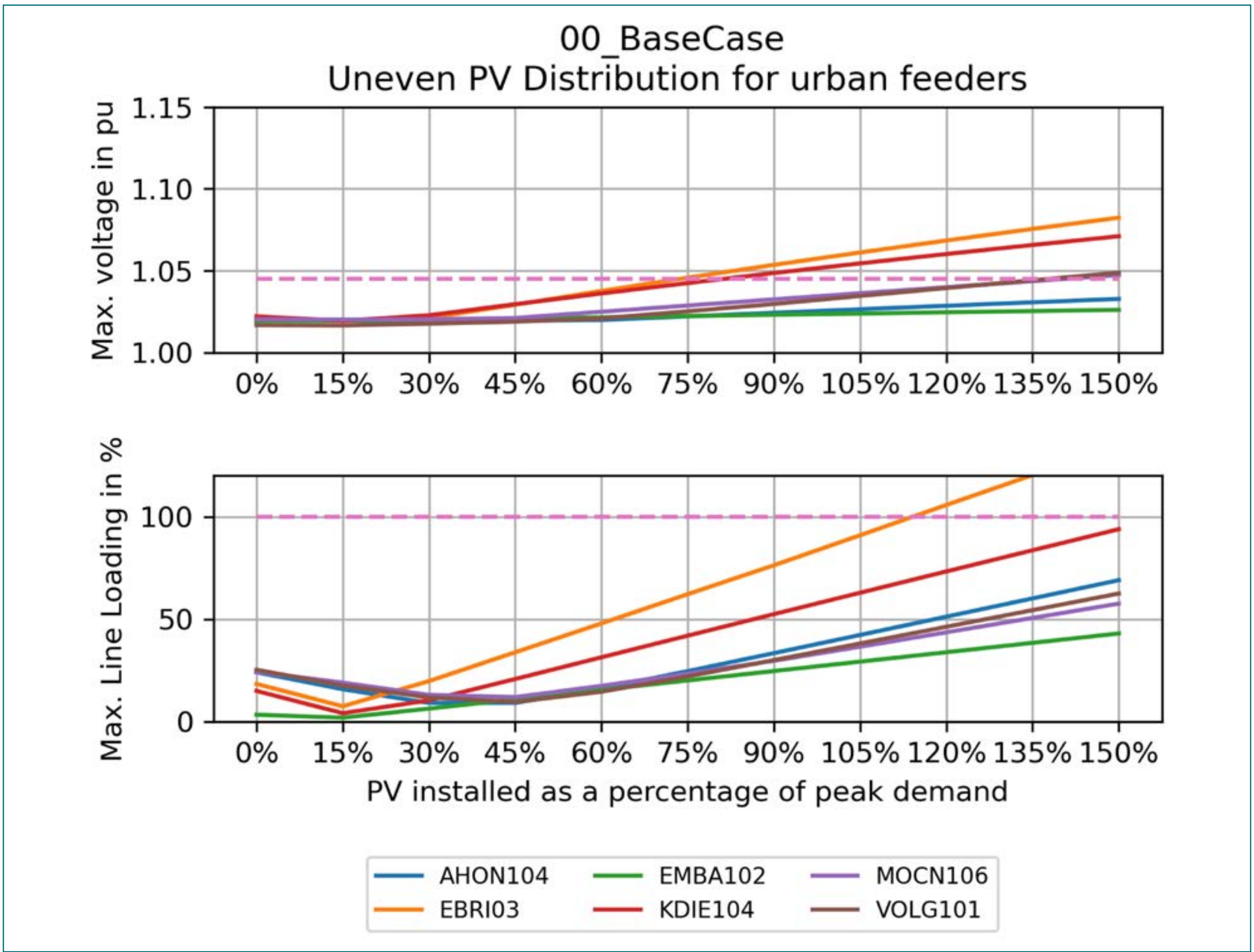
Figure 33: Maximum feeder voltage and line loadings with increasing PV penetration for the urban feeders, uniform PV distribution



loading but at PV penetration levels above 45% typically the PV infeed is higher than the minimum load, leading to increasing loading levels violated.

With an uneven PV distribution, shown in Figure 34, the impacts from PV are only slightly worse compared to the uniform PV distribution. In some of the feeders, the load distribution is already unfavourable, with a majority of load located towards the end of the feeders. Therefore, also the allocation of PV towards the end of the feeders does not yield much worse results. Maximum PV penetration levels for the two feeders EBRI03 and KDIE104 are slightly worse compared to the uniform PV distribution, at approx. 75% and 80% respectively. Here too, loading violations only occur at 110% for EBRI03, with voltage violations occurring before that at lower PV penetration levels.

Figure 34: Maximum feeder voltage and line loadings with increasing PV penetration for the urban feeders, uneven PV distribution

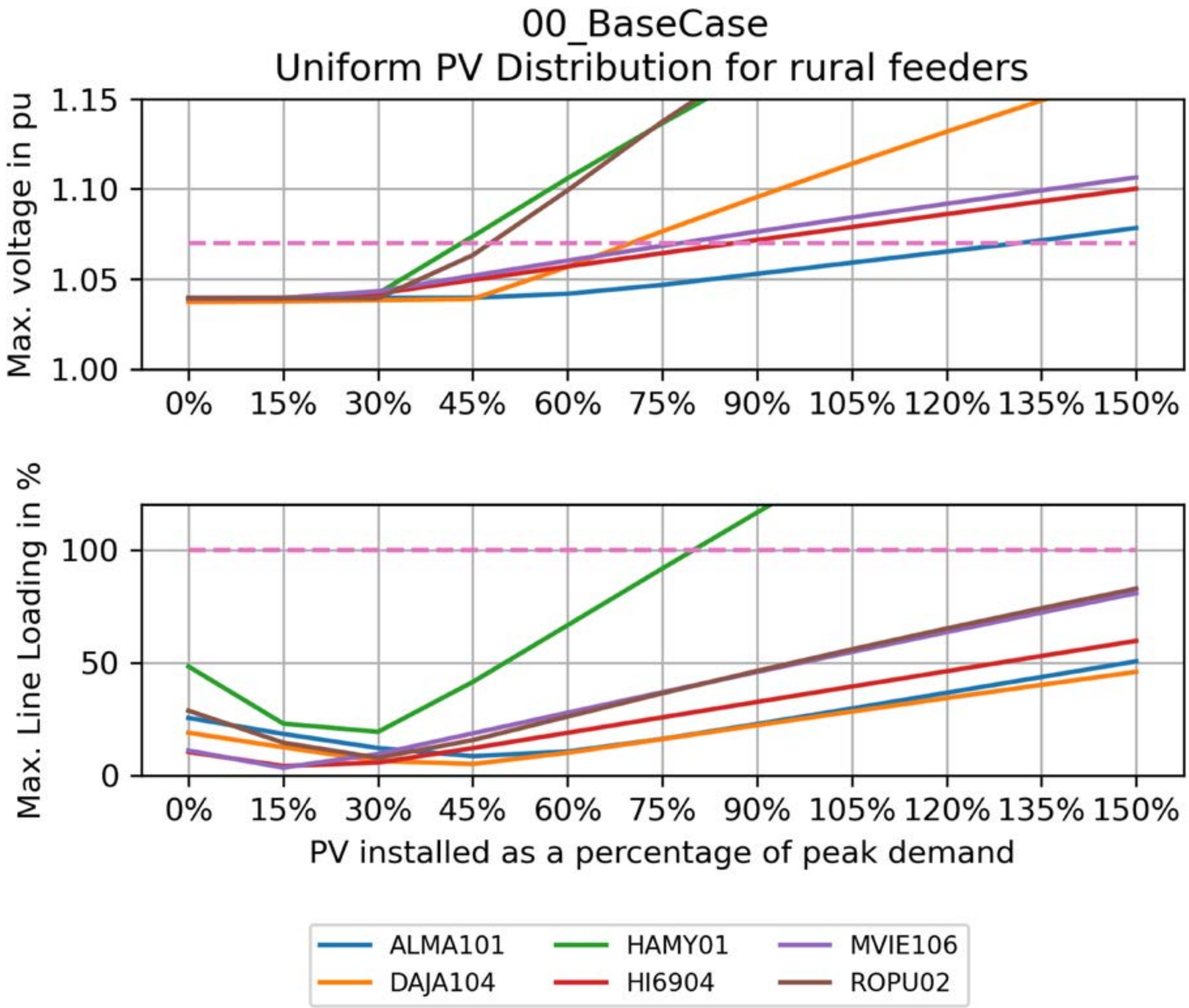


8.2 RURAL FEEDERS

Rural feeders are often much longer and have a smaller cross-section. Therefore, voltage violations are much more likely to occur in these cases. Figure 35 shows the results for the rural feeders in the case of uniform PV distribution. In these cases, the voltage threshold is set to 1.07 p.u., leaving a 3% voltage range for the LV network, so that the voltage is kept below 1.1 p.u.

As can be seen, maximum PV penetration levels with regard to voltage violations are very diverse, reaching from approximately 45% for HAMY01 and ROPU02 to 150% for VOLG101. In terms of overloading, only HAMY01 shows problems. However, voltage violations are reached before overloading occurs.

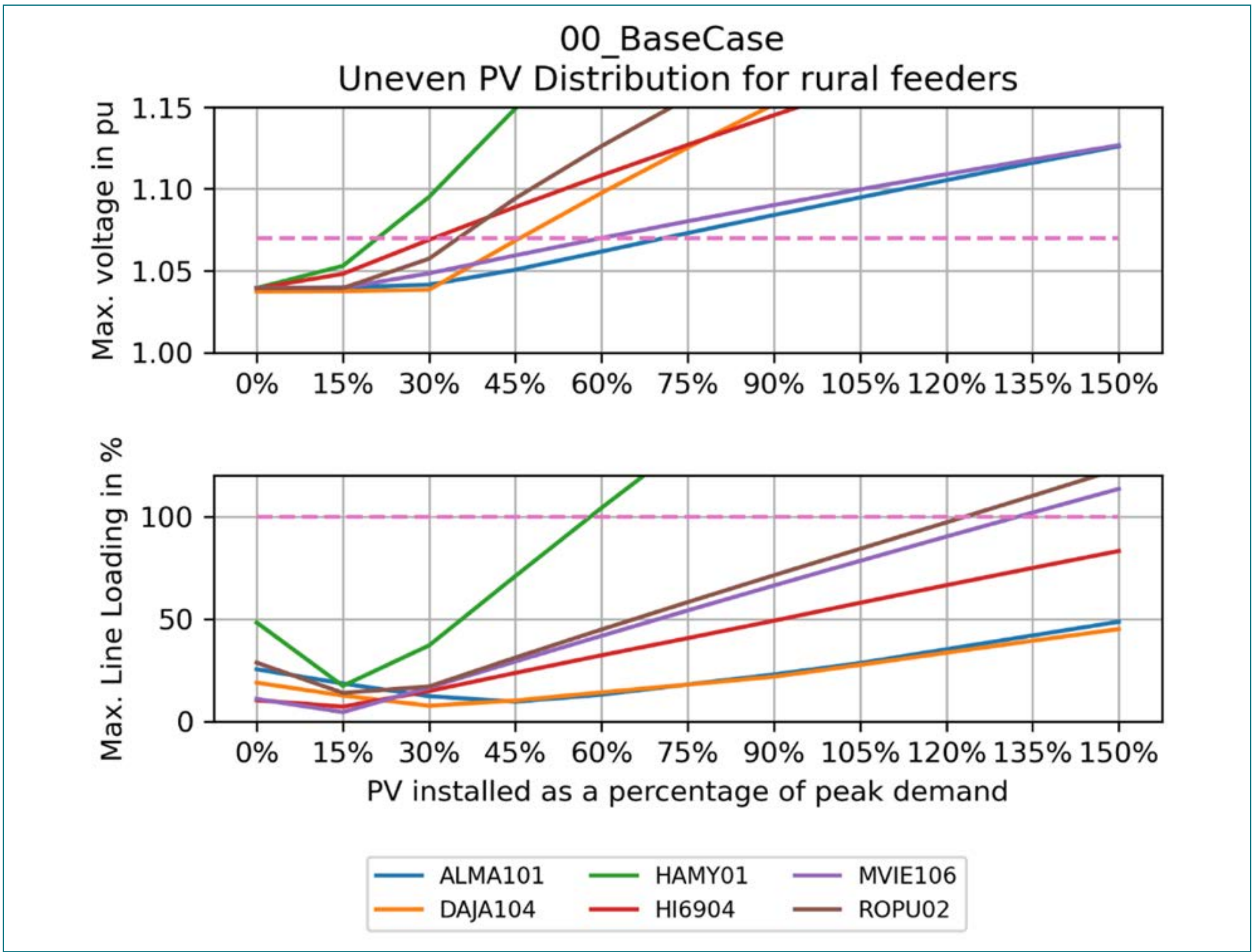
Figure 35: Maximum feeder voltage and line loadings with increasing PV penetration for the rural feeders, uniform PV distribution



In the uneven PV distribution scenario, shown in Figure 36, voltage violations occur much earlier, indicating the strong locational influence of PV distribution on the maximum PV penetration level. All feeders except VOLG101 are limited to a PV penetration level between approximately 20% and 75%.

Line loadings are worse compared to the uniform PV distribution scenario, but still voltage violations occur before line overloadings do.

Figure 36: Maximum feeder voltage and line loadings with increasing PV penetration for the rural feeders, uneven PV distribution



8.3 SUMMARY

Table 3 shows the overview of the selected feeders including their maximum PV penetration levels for the uniform and uneven PV penetration scenarios. As can be observed, maximum PV penetration levels vary widely. In particular, feeders with a high distance from the primary substation show low PV penetration levels. On the other hand, feeders with short distances from the primary substations, most commonly found in urban areas, show PV penetration limits even above 150%. There are no clear indications with regard to the peak load or the share of 1-phase lines if these are more likely to cause a high or low PV hosting capacity.

Table 3: Feeder characteristics and maximum PV penetration levels for uniform and uneven PV distribution

SELECTED FEEDER	VOLTAGE LEVEL	PEAK LOAD	FEEDER LENGTH	SHARE 1-PHASE	PV SHARE	URBAN/ RURAL	MAX SUBSTA-TION DISTANCE	MAX PV UNIFORM	MAX PV UNEVEN
EMBA102 (EdeSur)	12.47 kV	4.7 MVA	12 km	22%	9.1%	Urban	2 km	> 150%	> 150%
MOCN106 (EdeNorte)	12.47 kV	4.4 MVA	29 km	63%	20.6 %	Urban	4 km	> 150%	140%
DAJA104 (EdeNorte)	12.47 kV	2.8 MVA	153 km	68%	1.7 %	Rural	46 km	70%	45%
ALMA101 (EdeNorte)	12.47 kV	1.8 MVA	132 km	90%	4.1 %	Rural	21 km	130%	70%
MVIE106 (EdeSur)	12.47 kV	8.3 MVA	31 km	26%	15.5 %	Rural	14 km	80%	60%
AHON104 (EdeSur)	12.47 kV	7.1 MVA	27 km	44%	17.4 %	Urban	4 km	> 150%	> 150%
HI6904 (EdeEste)	12.47 kV	5.4 MVA	117 km	41%	0.9 %	Rural	34 km	85%	30%
HAMY01 (EdeEste)	12.47 kV	7.9 MVA	187 km	81%	10.4 %	Rural	36 km	45%	20%
ROPU02 (EdeEste)	4.16 kV	3.6 MVA	95 km	64%	0 %	Rural	22 km	50%	35%
EBRI03 (EdeEste)	12.47 kV	9.7 MVA	66 km	53%	19.7 %	Urban	9 km	80%	75%
KDIE104 (EdeSur)	12.47 kV	10.1 MVA	119 km	72%	10.7 %	Urban	9 km	95%	80%
VOLG101 (EdeNorte)	12.47 kV	6.7 MVA	76 km	66%	69.4 %	Rural	9 km	145%	140%

9. SIMULATION RESULTS ON MITIGATION MEASURES

Las siguientes soluciones tecnológicas se simulan para mostrar su potencial para aumentar la capacidad de alojamiento de energía fotovoltaica en los alimentadores simulados.

Table 4: List of technology options for increasing PV hosting capacity.

Solution	Description
HV/MV voltage setpoint optimization	HV/MV transformers currently operate at 1.04 p.u. in rural grids and 1.02 p.u. in urban grids. These voltage setpoints can be lowered, if no undervoltage problems exist in the feeder. This allows for more PV generation, without violating the upper voltage boundary.
Active power-dependent voltage control at the HV/MV transformer	The voltage setpoint of the HV/MV transformer can be regulated dynamically depending on active power flow. E.g. at high demand, the setpoint can be set high (e.g. 1.05 p.u.), while at low demand due to PV generation or even reverse power flows the setpoint can be set low (e.g. 1.0 p.u.).
Wide area voltage control at the HV/MV transformer	Refining the automatic voltage regulation by the HV/MV transformer by adding a wide area monitoring system, which measures the voltage at different points in the grid and switches the transformer's tap changer accordingly. E.g. if a high voltage above a certain threshold is measured, the setpoint is lowered; if a low voltage is measured, the setpoint is increased. This requires additional communication between the voltage measurement point(s) and the HV/MV transformer.
Reactive power control of PV inverters (Q(P) and Q(U) control)	Reactive power consumption lowers the voltage across the line. If the PV inverter consumes reactive power during high PV infeed, this mitigates part of the induced voltage rise. The characteristic can be either constant, active power-dependent (Q(P) control) or voltage-dependent (Q(U) control).
PV generation cap at 70% of installed panel capacity	PV inverters can be capped at a certain percentage of the installed PV panel capacity. The maximum PV panel output is typically never reached due to efficiency losses and lower PV output at higher temperatures compared to laboratory conditions. By capping the PV inverter to about 70% of PV panel capacity, only 2-5% of annual energy is lost.
PV peak shaving by battery usage	A battery can provide PV peak shaving as well. E.g. with the additional battery, the PV inverter may be capped to 50%, which incentivizes the battery operation to only charge during high PV output, as opposed to charging the battery as soon as PV output surpasses the household demand. Not requiring the PV cap may not alleviate the grid, as the maximum PV power is still fed into the grid as soon as the battery is full.
Reinforcement of lines and transformers	Lines and transformer may be upgraded to allow a higher share of PV. This is usually the least economical solution and only necessary at very high PV shares.

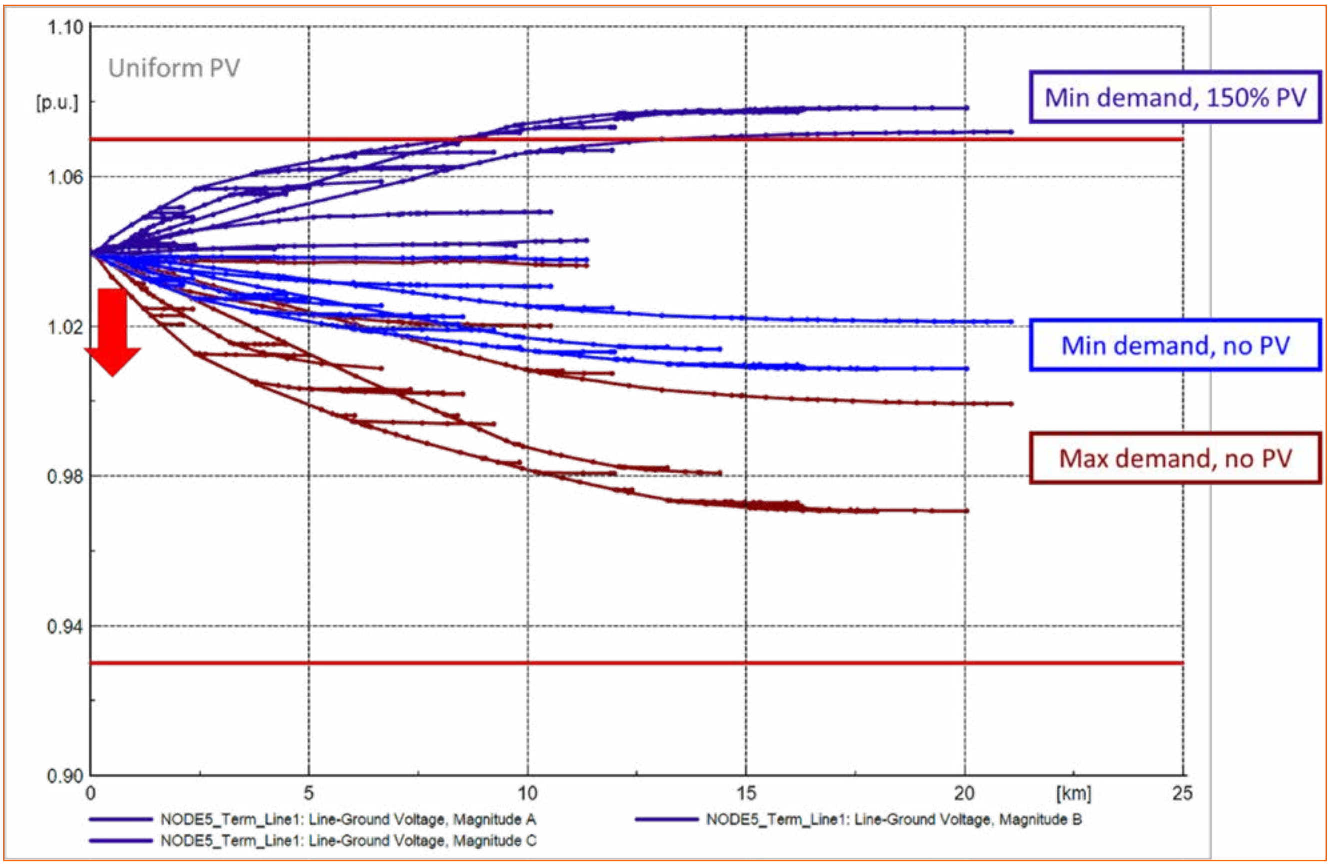
The PV hosting capacity before and after the implementation of the individual measures is compared. The solutions are ranked based on their technical potential and economic attractiveness.

For better display, only the results from the rural feeders for the uniform PV distribution scenario are shown in the following sections. The full results for all feeders and PV distribution scenarios can be found in the summary chapter 9.8.

9.1 HV/MV VOLTAGE SETPOINT OPTIMIZATION

The voltage setpoint for the feeders has been set to 1.04 p.u. in the case of rural feeders, and 1.02 p.u. in the case of urban feeders. Depending on the voltage drop for each respective feeder, a more optimal voltage setpoint can be found. This is illustrated by the following example in Figure 37 with the feeder ALMA101.

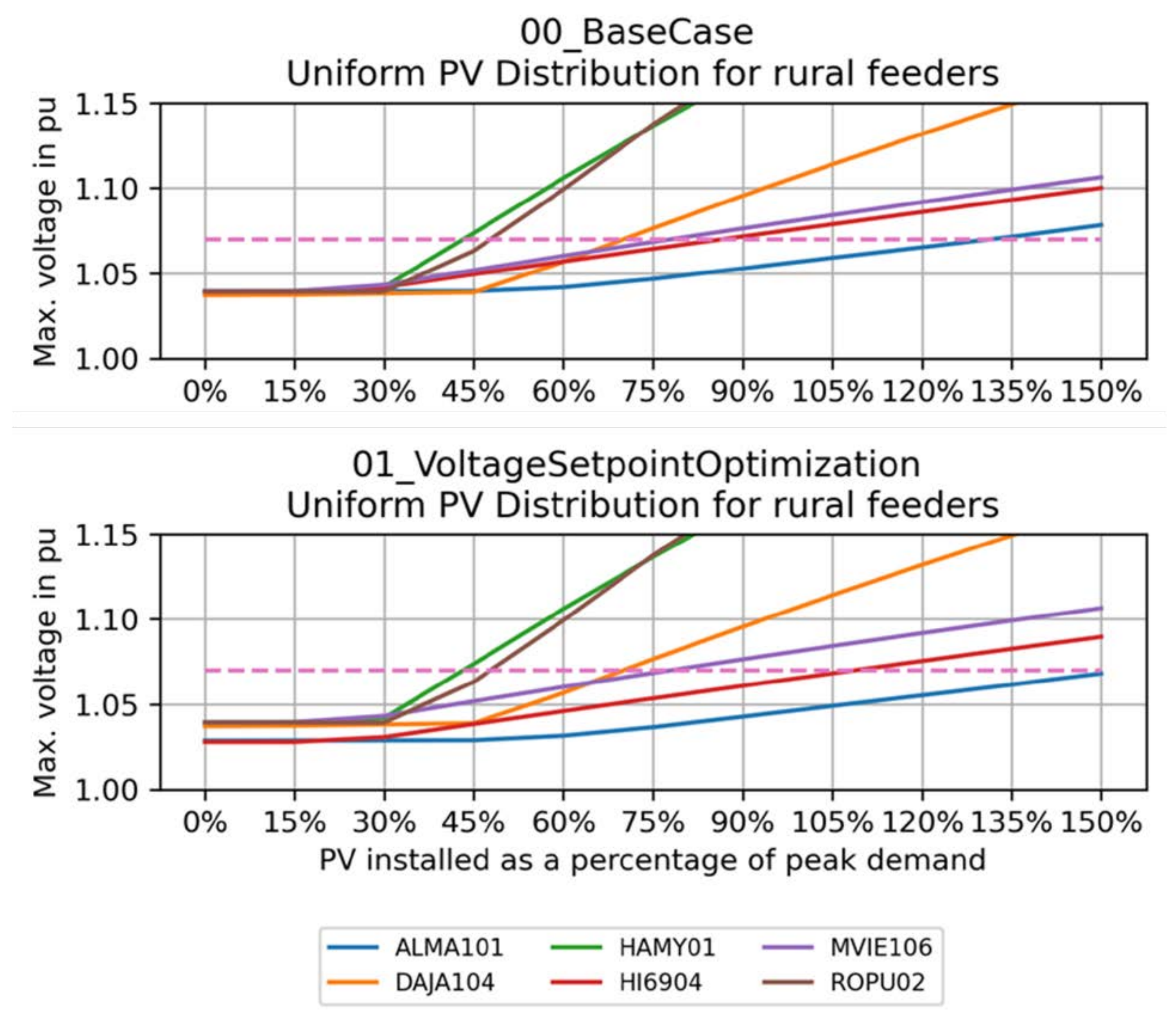
Figure 37: Illustration of the setpoint optimization. Indicated by the red arrow is the potential to reduce the voltage setpoint so that the maximum amount of PV can be integrated without creating undervoltage problems during peak demand



By lowering the voltage setpoint of the primary transformer, it is possible to keep within the voltage boundaries both during peak demand as well as during the scenario of 150% PV penetration level. In this case, the voltage is lowered by approximately 2%. In such a case, a good knowledge of the actual minimum voltages in the feeder is needed, that can be obtained by simulation and verified by measurements.

Figure 38 shows the impact on the maximum voltage for the rural feeders and a uniform PV distribution. As can be seen, only some of the feeders can host a higher PV capacity when applying this mitigation measure. The reason is that on some feeders undervoltage problems are already existing, which prohibits a reduction of the voltage setpoint. In other cases, however, an increase of approximately 15% in PV penetration is possible.

Figure 38: Comparison of maximum voltages for the base case and the mitigation measure „HV/MV voltage setpoint optimization"



9.2 ACTIVE POWER-DEPENDENT VOLTAGE CONTROL AT THE HV/MV TRANSFORMER

With an appropriate control, the voltage setpoint at the primary substation can be variably adjusted depending on the power flow into the distribution network. This control is sometimes also labelled as "compound regulation". The applied control in the case of the selected feeders keeps the voltage at a high voltage setpoint of 1.05 if the power flow is greater than 50% of peak demand. When the power flow is reduced or even reversed, the setpoint is gradually reduced up to a minimum voltage setpoint of 1.0 p.u.

In Figure 39 the control curve for the feeder EBRI03 is depicted, which has a peak demand of 9.7 MVA. The voltage setpoint is reduced below 50% of peak demand (4.85 MVA).

Figure 39: Active power-dependent voltage control curve at the primary substation for EBRI03

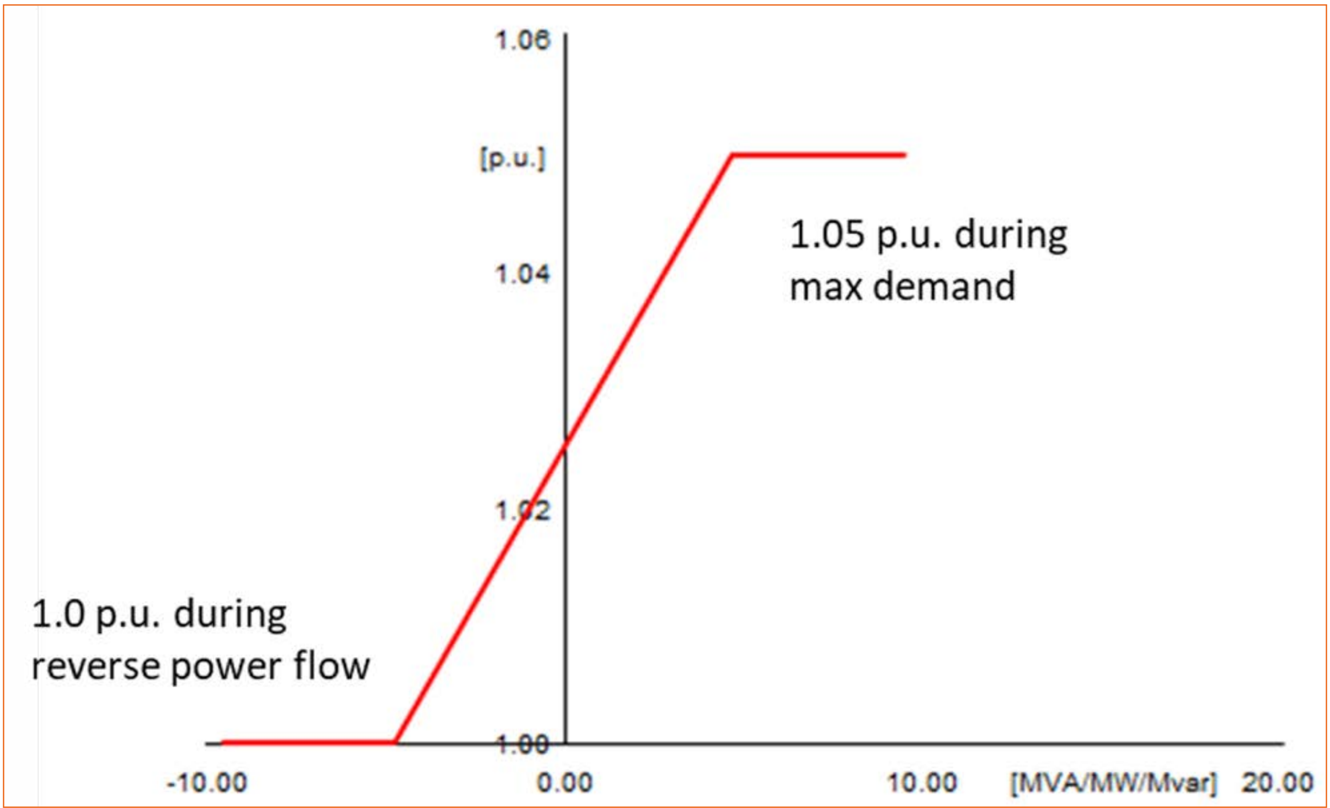
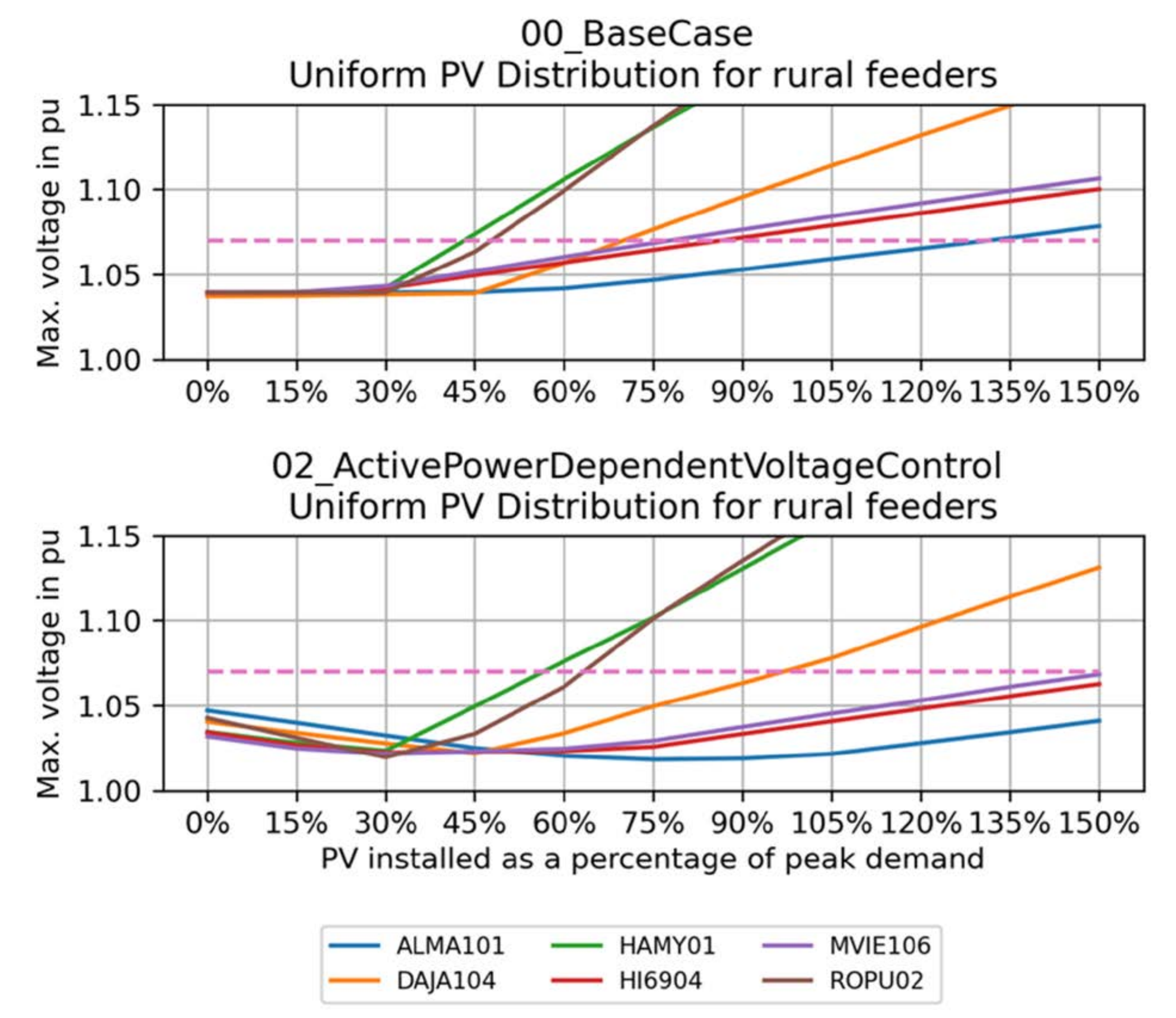


Figure 40 depicts the resulting increase of PV penetration levels. As can be observed, the resulting PV hosting capacities are 15% to 30% higher, as the voltage can be reduced only when PV infeed is high, as opposed to the first mitigation measure in which the voltage setpoint is permanently reduced regardless of the power flow across the transformer.

Figure 40: Comparison of maximum voltages for the base case and the mitigation measure „Active power-dependent voltage control"



9.3 WIDE AREA VOLTAGE CONTROL AT THE HV/MV TRANSFORMER

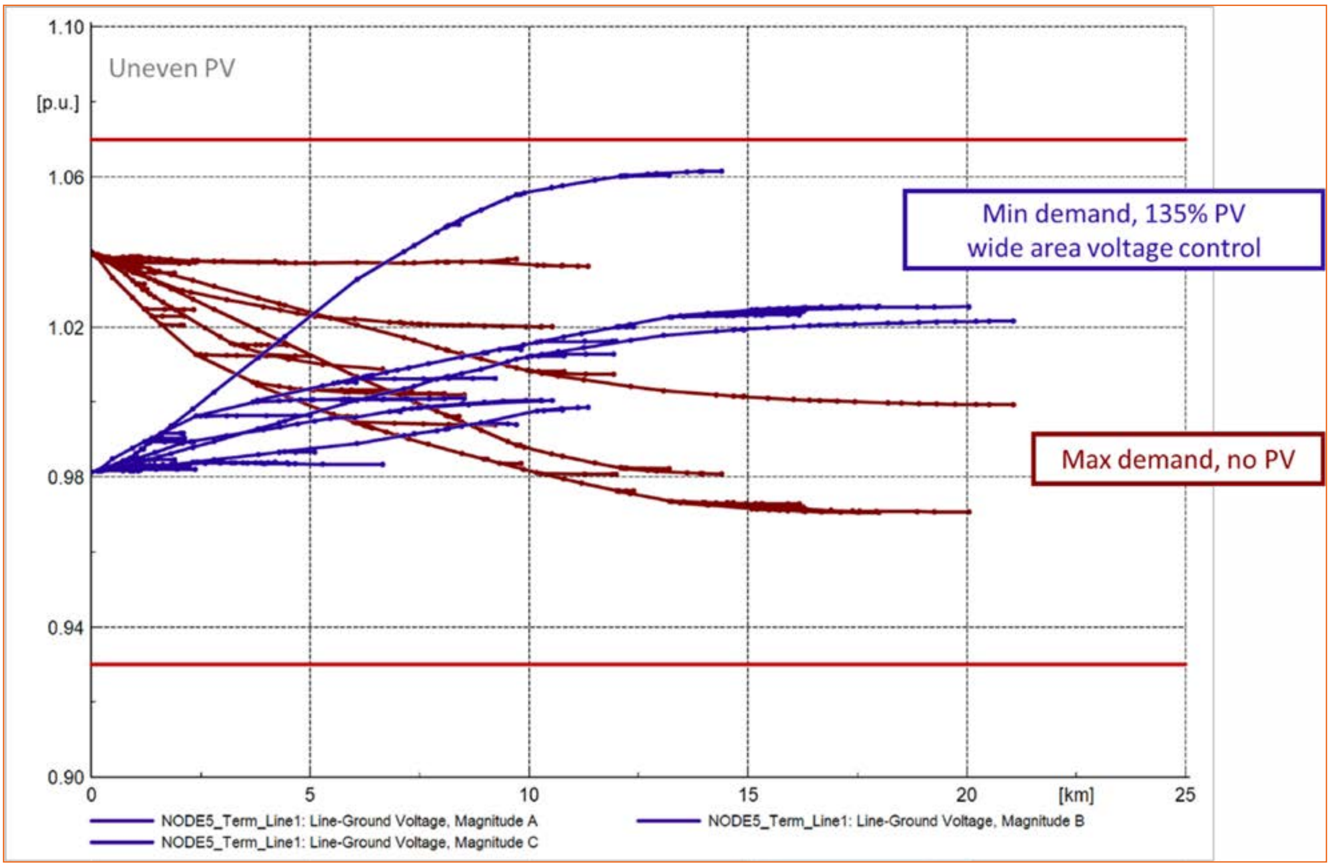
Wide area voltage control is defined as using voltage measurements from different points in the grid as an input to the voltage controlling on-load tap changing transformer, which will aim for a setpoint that allows all points included in the control scheme to operate within the allowed voltage range.

In the selected feeders, the primary substation voltage was regulated in such a way between 0.98 and 1.04 p.u. (rural substations) or 0.98 and 1.02 p.u. (urban substations) that the voltage in the distribution feeder was kept as far as possible within the allowed voltage range.

Hence, if the voltage drop during peak demand for a rural feeder is 5%, the voltage is set to a value between 1.03 and 1.04 p.u. If a voltage increase of 5% due to PV infeed occurs, then the voltage of the primary substation is reduced to a level of 0.98 to 0.99 p.u. In feeders, where the voltage drop or increase is greater than the voltage range (e.g. 10%), the voltage setpoint is shifted as far as possible while adhering to the allowed voltage regulation range at the primary substation transformer.

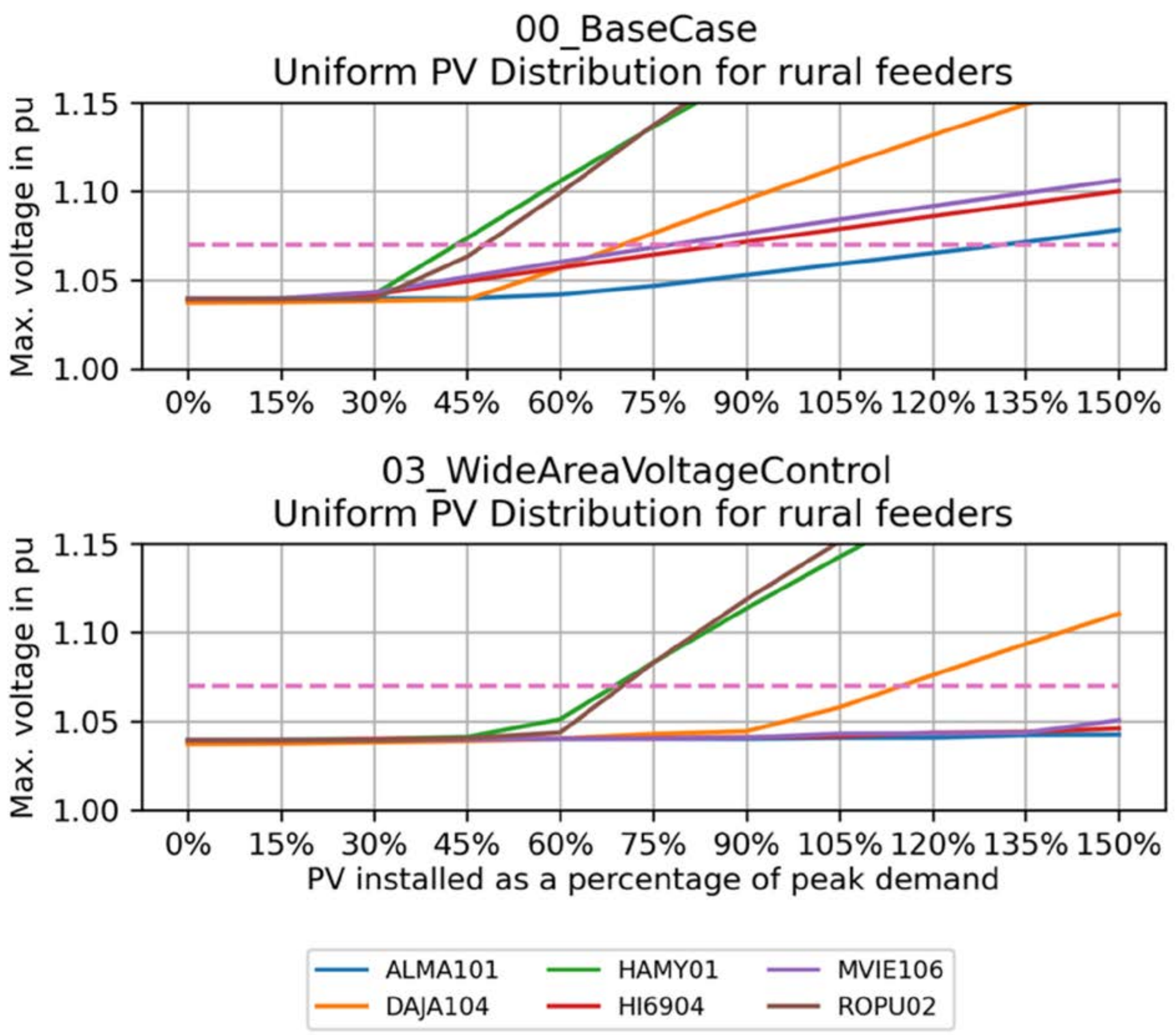
Figure 41 shows an illustration of the resulting voltage profile for the feeder ALMA101.

Figure 41: Voltage profile during peak demand and 135% uneven PV penetration with applied wide area voltage control



Compared to the active power-dependent voltage control, the wide area voltage control further improves the overvoltages for the feeders. This is shown in Figure 42. PV penetration limits can be increased by more than 30% in most cases. However, wide area voltage control is also much more expensive than the previous two mitigation measures, as it requires measurement and communication infrastructure to the most vulnerable nodes of a feeder, where the largest voltage deviations are expected.

Figure 42: Comparison of maximum voltages for the base case and the mitigation measure „Wide area voltage control"



9.4 REACTIVE POWER CONTROL OF PV INVERTERS (COSPHI(P) AND Q(U) CONTROL)

To reduce the voltage rise at the point of connection that is caused by the injection of active power at the connection point of a PV unit, the inverter can be operated with an under-excited power factor. It will draw reactive current and thus lower the voltage. Two reactive power control curves were simulated to show the respective impact, with each a power factor down to 0.95 under-excited.

Figure 43: Applied cosphi(P) control

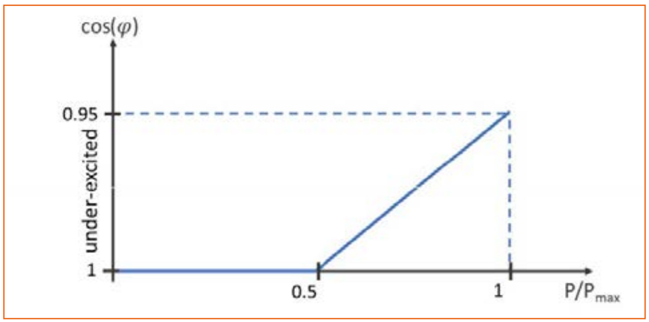
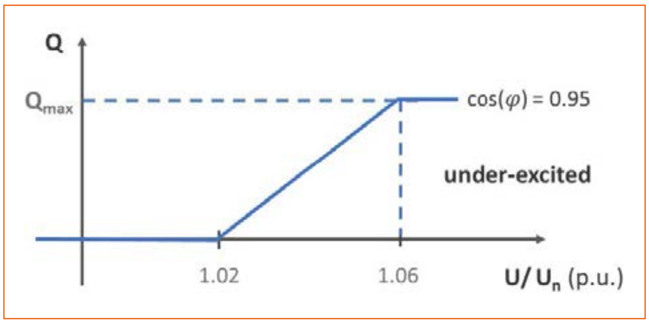


Figure 44: Applied Q(U) control



Such behavior of PV inverters is required from several German grid operators, for example, and the current German low voltage grid code requires such capabilities from PV inverters. However, the reactive currents will increase line and transformer loading while reducing the voltage. As voltage problems are more prominent in the Dominican Republic compared to overloading, this measure may be an appropriate requirement.

Figure 45 shows an illustration of the reduction in voltage due to cosphi(P)-control:

Figure 45: Voltage profile of ALMA104 during 150% PV penetration (uniform) and applied cosphi(P) control

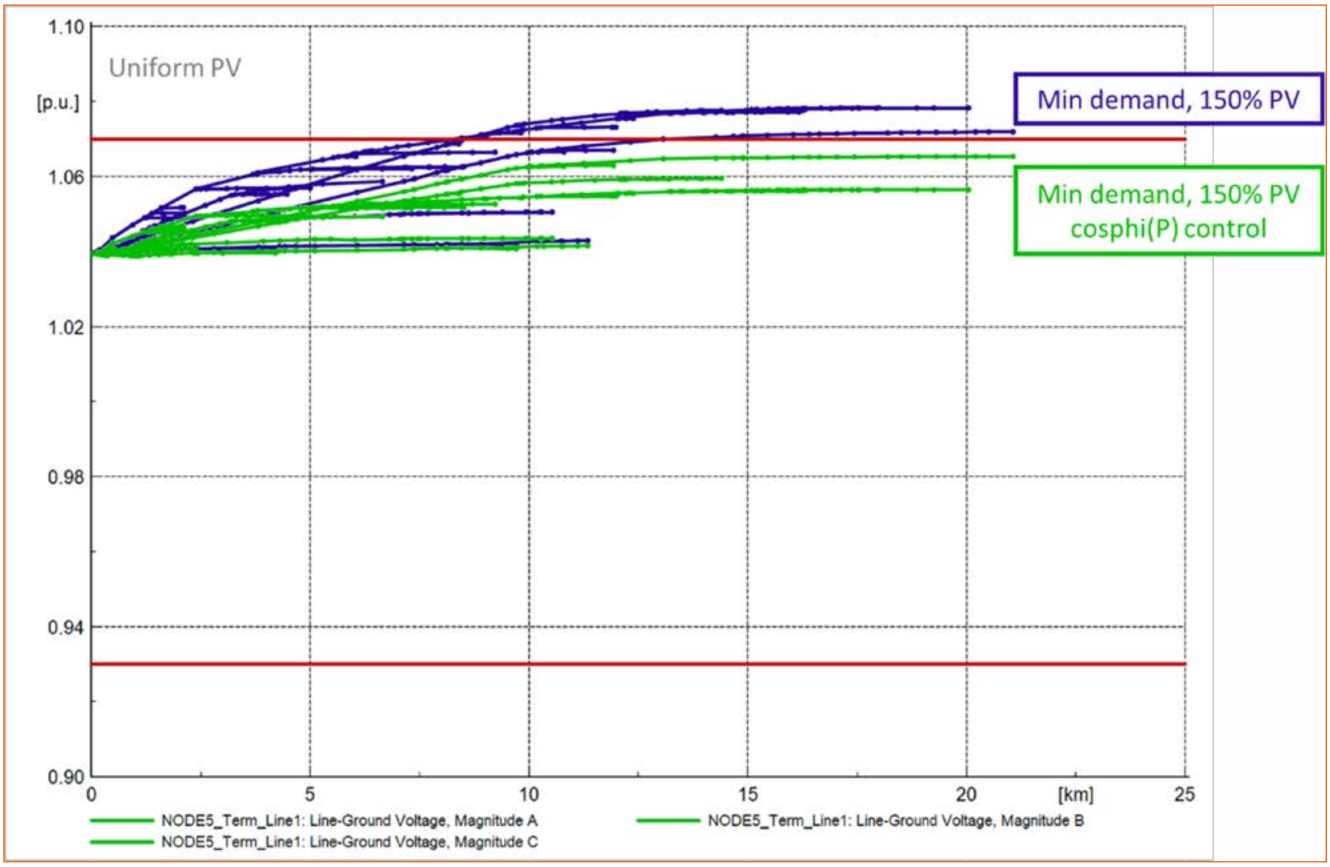
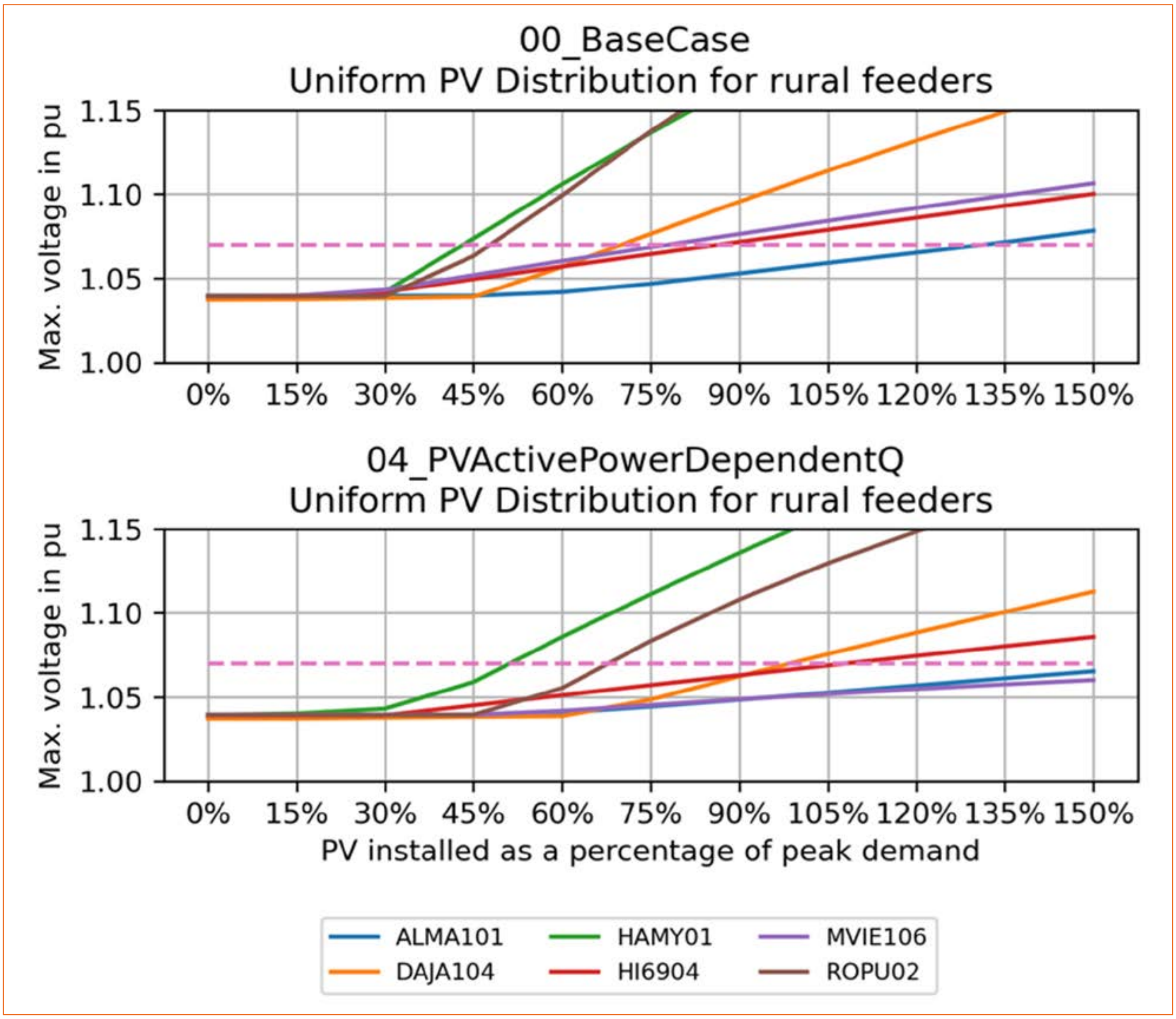


Figure 46 shows the results with regard to increased PV penetration levels with applied cosphi(P) control. The results for Q(U) control are depicted in the summary chapter 9.8.

Voltage problems are reduced, leading to an increased PV hosting capacity of ca. 10% to 30%.

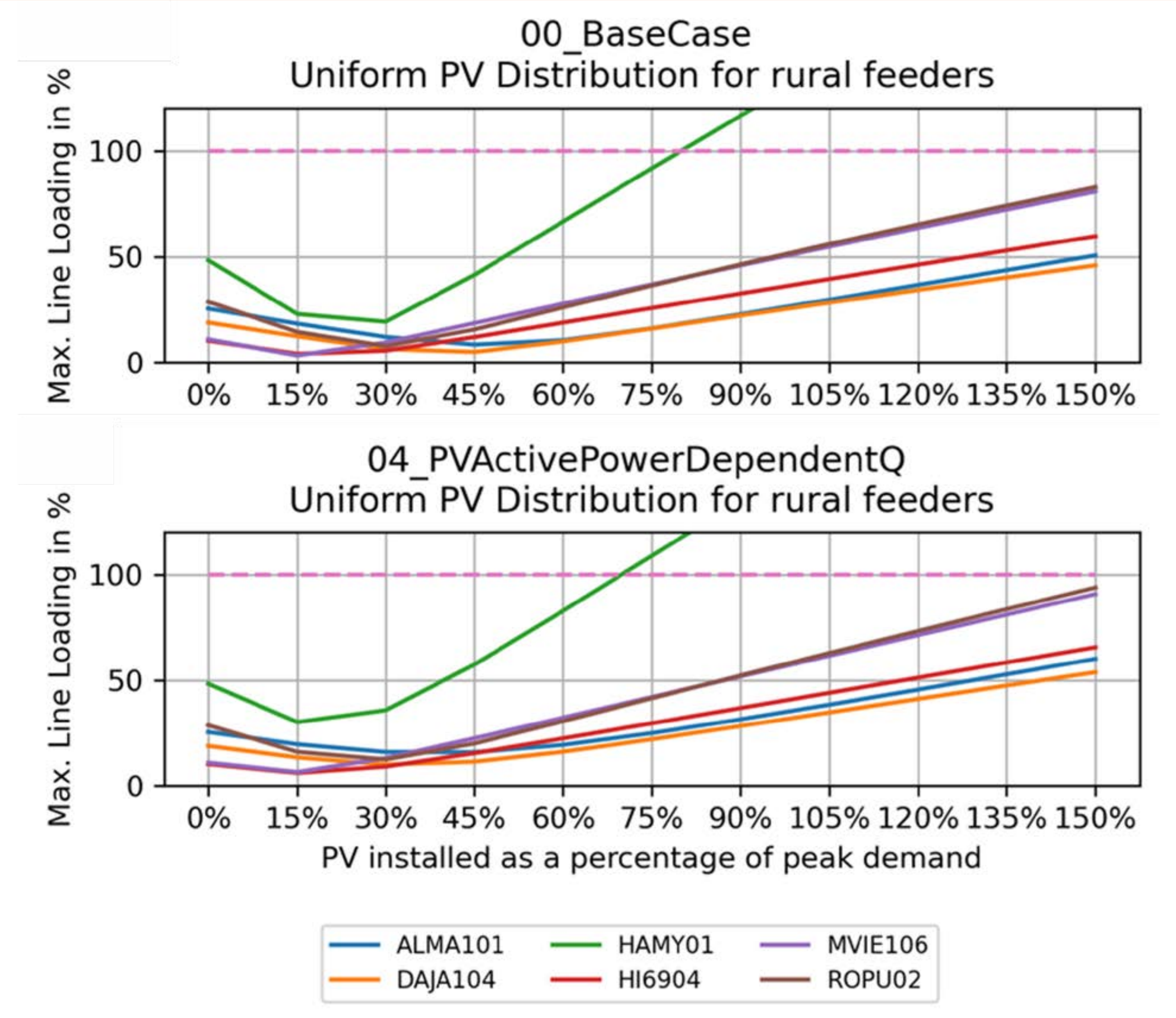
However, due to the increased reactive power flow, the line loadings are aggravated. In terms of line loadings, the PV

Figure 46: Comparison of maximum voltages for the base case and the mitigation measure „Reactive power control with cosphi(P) characteristic



hosting capacity for HAMY01 is for example reduced by approximately 10%. As line loadings are however less of a concern in the selected feeders, such reactive power settings for the PV inverters would be still suitable.

Figure 47: Comparison of maximum line loadings for the base case and the mitigation measure „Reactive power control with cosphi(P) characteristic"



9.5 PV GENERATION CAP AT 70% OF INSTALLED PANEL CAPACITY

PV panels will usually not reach their installed capacity during normal operation due to heat and dust. Typically, the maximum power output reaches only approximately 70% to 90% of installed capacity. Furthermore, actual peak power is usually reached only a few times a year. If the requirement is set that the grid actually has to be able to absorb the peak power, the impact of PV will be overestimated for much of the year. The peak power of PV units can therefore be capped to 70 or 80 % at relatively low yearly losses of energy. These losses typically lie in a range of 2 to 4% of annually lost energy and are generally seen as an acceptable value for renewable curtailment and/or capping to reduce the impact on the power grid.

Figure 48 illustrates that only little energy is lost compared to the overall PV production during a sunny day.

Figure 48: Illustration of a PV generation cap at 70% of installed panel capacity

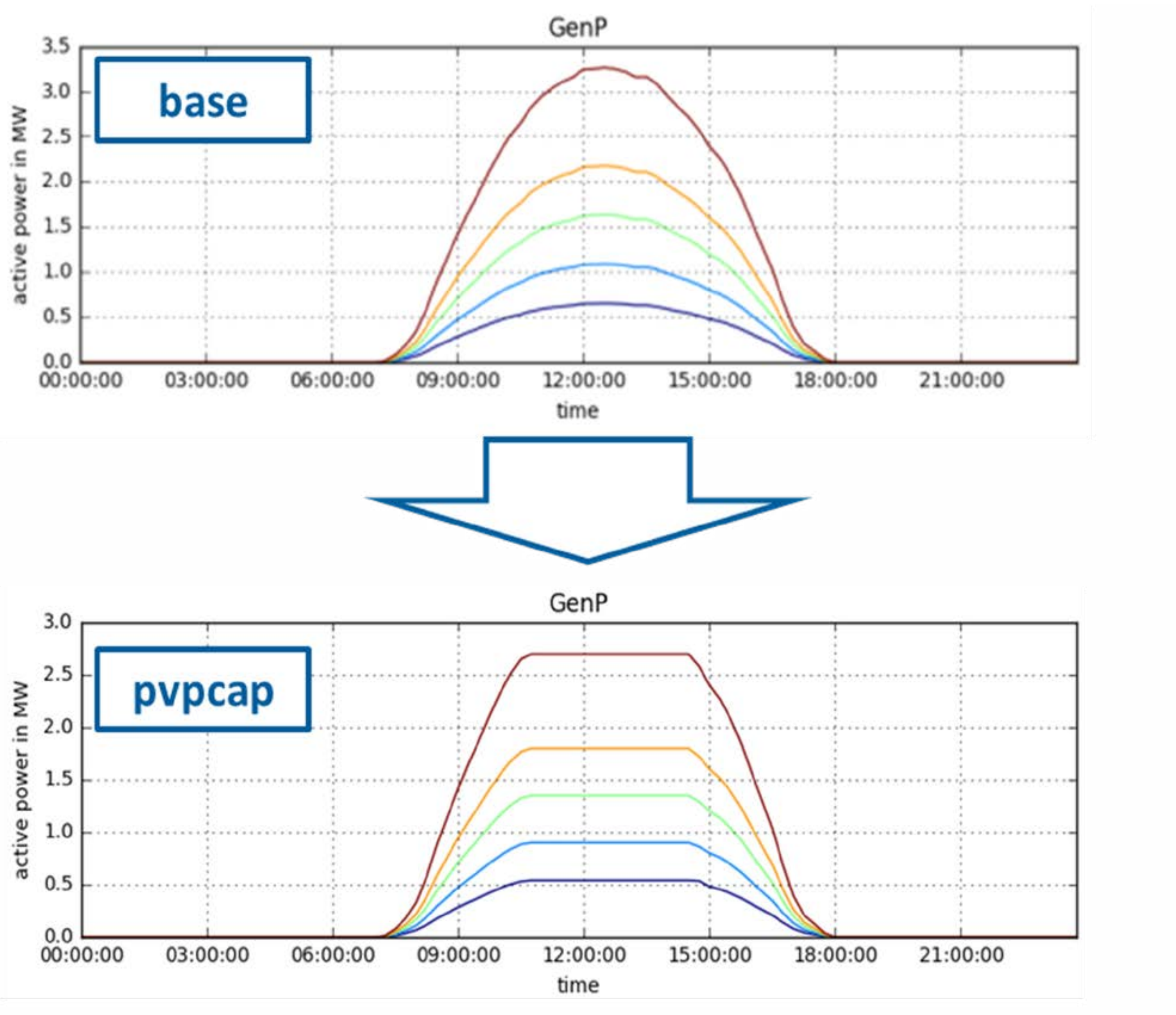
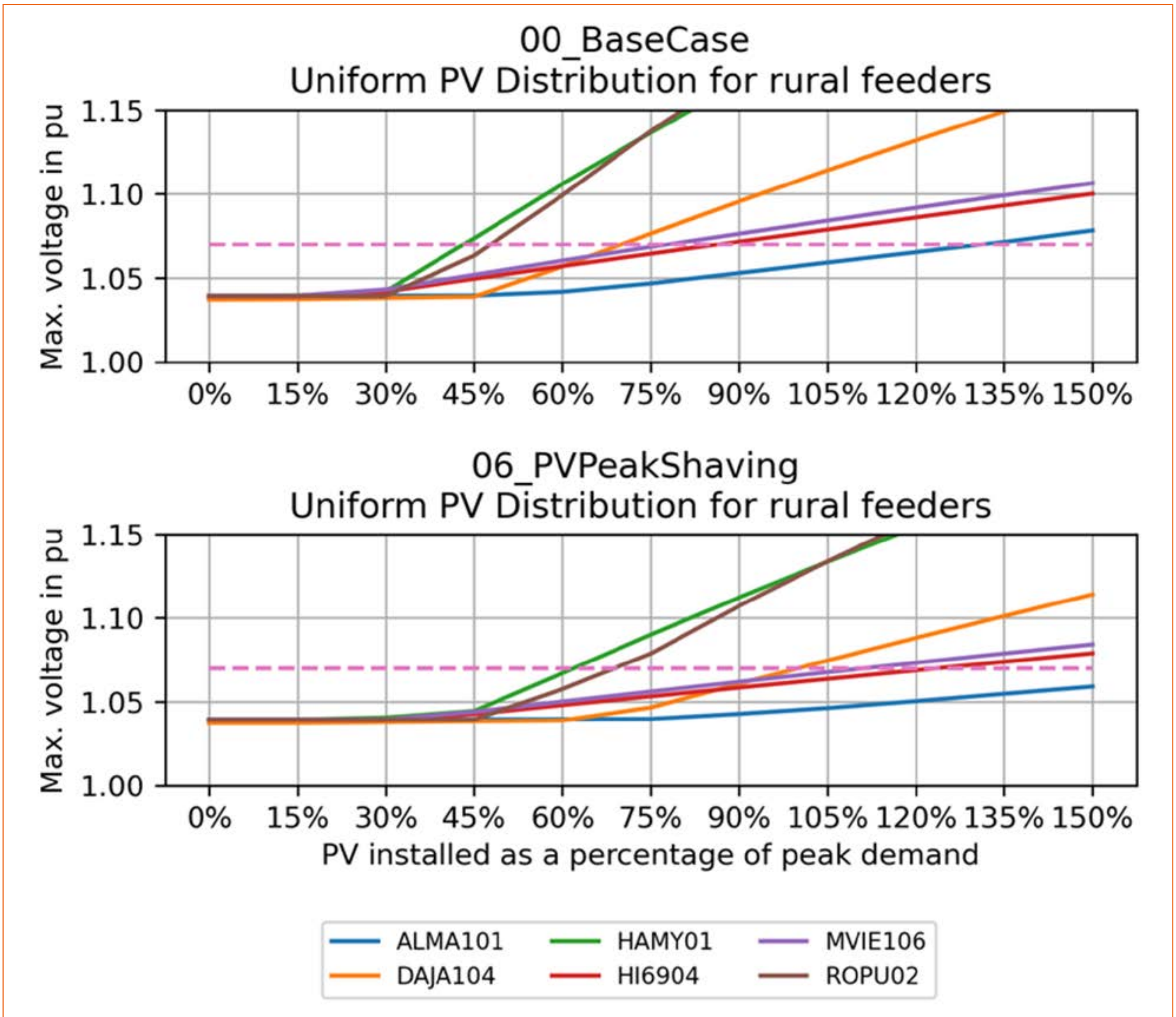


Figure 49 shows the results with regard to increased PV penetration levels. As can be seen, this effective reduction of 30% PV penetration leads to an increase in PV hosting capacity of 15% to 30%. At the same time, also maximum line loadings are reduced, as can be seen in Figure 50.

Figure 49: Comparison of maximum voltages for the base case and the mitigation measure „PV 70% generation cap"



9.6 PV PEAK SHAVING BY BATTERY USAGE

A similar effect as in the case of the 70% PV generation cap can be reached by using batteries to shave off the peak from the PV generation.

If an incentive is set for batteries for self-consumption, battery owners will usually try to charge their battery as quickly as possible as soon as their PV units starts generating. This leads to the behavior depicted in Figure 51, where the battery charges in the morning, but is already full at the time the PV unit hits its peak power. This has no positive impact on the grid even though self-consumption is maximized.

To observe a positive impact on grid operation, batteries need to be operated in peak shaving mode, where the battery starts

Figure 50: Comparison of maximum line loadings for the base case and the mitigation measure „PV 70% generation cap"

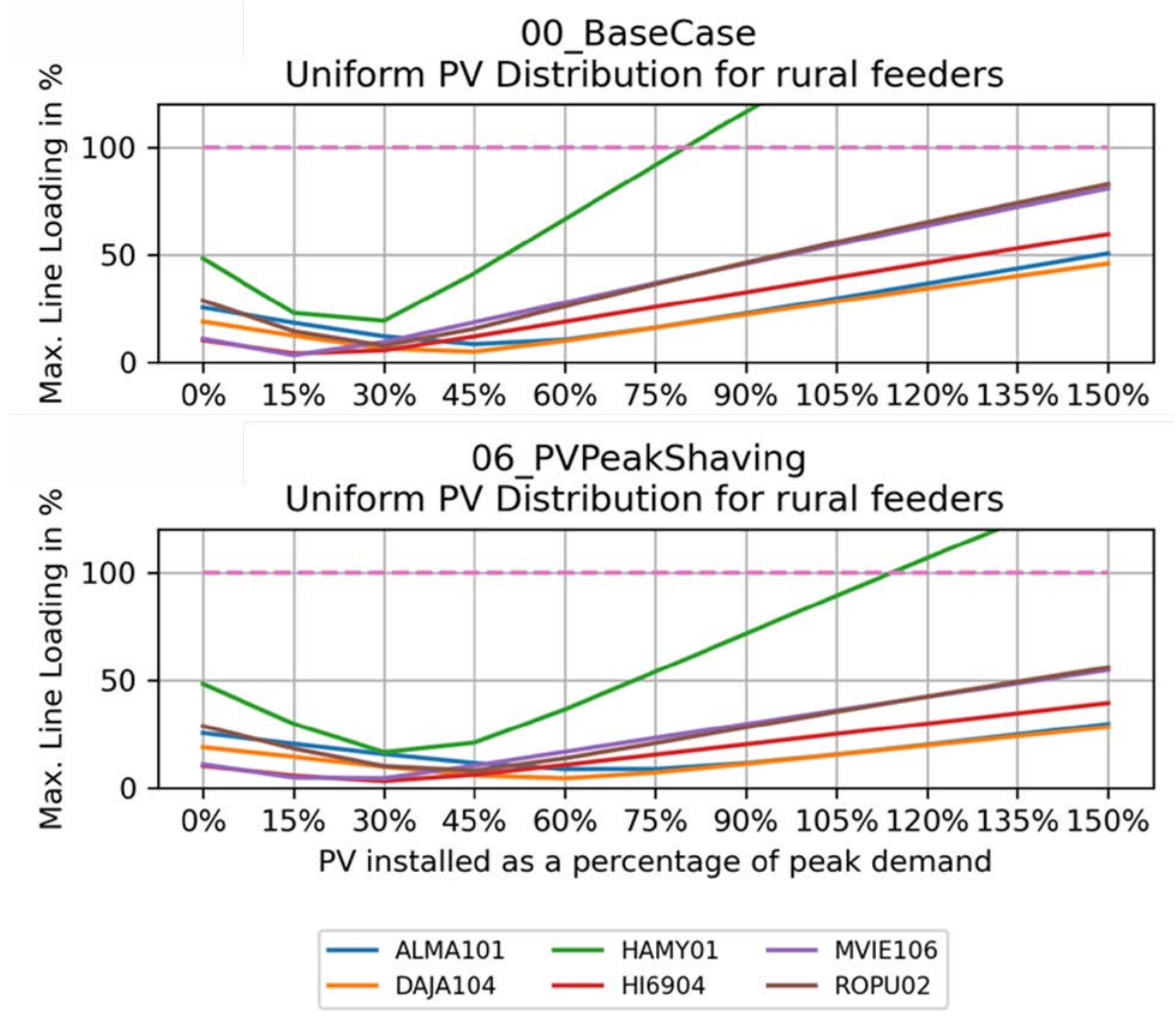
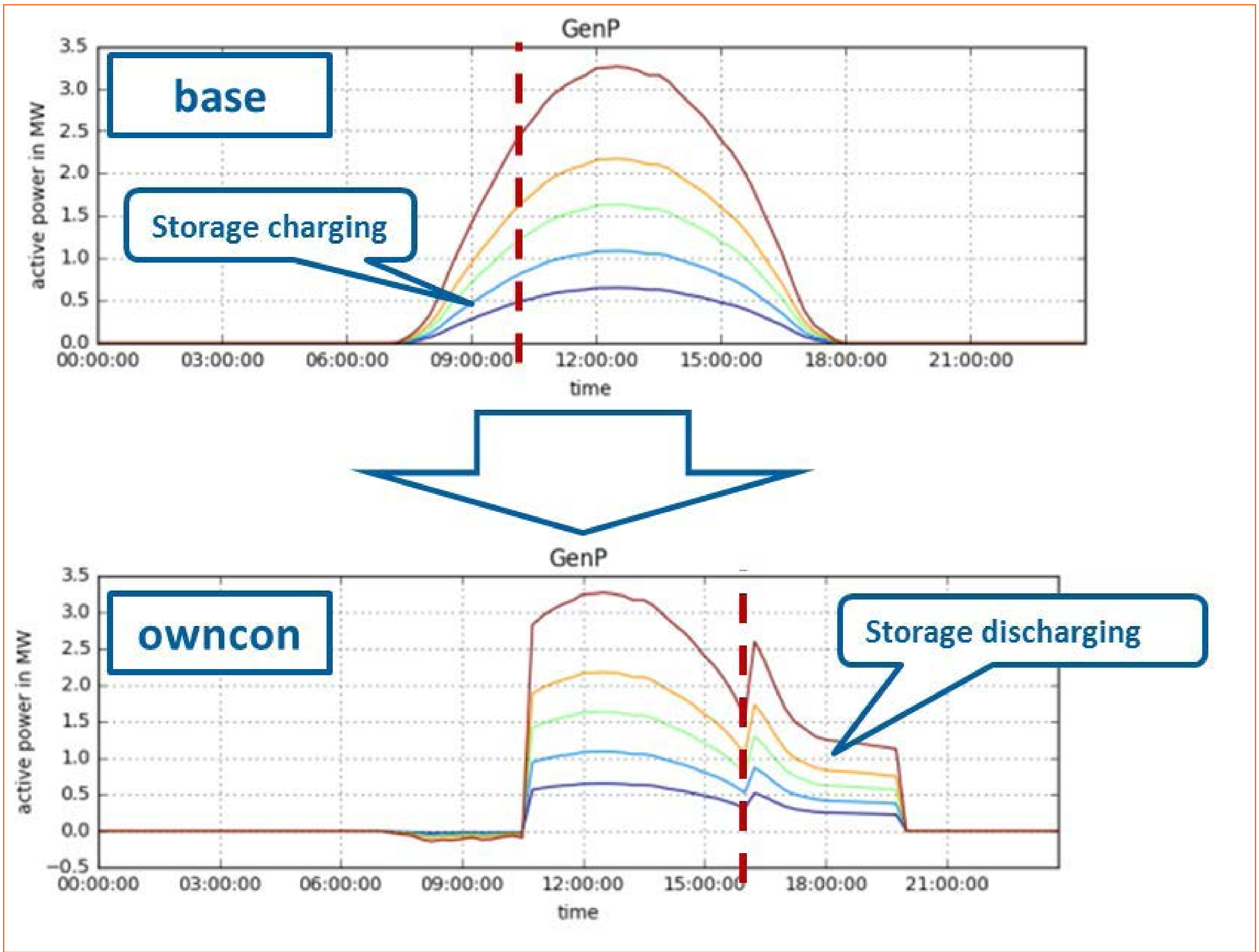


Figure 51: Battery operation with the optimization of own consumption, which does not relieve the distribution grid impact. Instead, it must be coupled with a PV cap as described in the previous chapter or other incentive measures



charging some time before mid-day and "shaves" the peak off the PV curve. This results in the same profile as for the 70% PV generation cap, as was depicted in Figure 48. Usually, the grid operator will have to set some incentive for this behaviour to be implemented by the system owners.

An incentive could for example be the cap on the inverter size as in the mitigation measure described in the previous chapter. If the cap is set even lower, e.g. at 50% or 60%, this incentivizes the PV plant owner to install a battery in order to not lose the otherwise freely generated electricity. A good balance between PV cap and battery incentives should be found in order to not penalize PV production too much while at the same time relieving the distribution grid from peak PV infeed.

9.7 REINFORCEMENT OF LINES AND TRANSFORMERS

Network reinforcement is the simplest and most effective, but also often the most expensive remedy to increase PV penetration in the distribution network. This solution helps alleviate both voltage and overloading issues. Due to insufficient data on costs and complexity with regard to which lines would need to be upgraded to allow for more PV penetration, this scenario was not explicitly simulated.

9.8 SUMMARY OF MITIGATION MEASURES

The following two chapters summarize the results of mitigation measures. Some of these mitigation measures offer good alternatives compared to the grid reinforcements that would otherwise be needed. The latter is often considered the most expensive option for increasing FV capacity, as replacing the lines involves a high capital and operation cost.

9.8.1 Uniform PV distribution

Figure 52 and Figure 53 show the maximum PV penetration levels with respect to voltage violations and overloading, respectively, for all feeders in the uniform PV distribution and comparing all different mitigation measures as well as the base case. The five left feeders are the urban feeders, while the seven feeders on the right present the rural feeders.

Comparing the different mitigation measures the following observations can be made:

- The voltage setpoint optimization can increase the PV hosting capacity in some but not all feeders;
- The active power-dependent voltage control greatly increases the PV hosting capacity in most cases, and is a control possibility that is easy to implement and effective to compensate for PV-induced voltage increases when carefully parametrized;
- The wide area voltage control is even more effective in increasing the PV hosting capacity, however, is a much more complicated and costly measure as measurements in the distribution feeder must be taken;
- The reactive power control measures by PV inverters are a very effective mitigation measure, reducing the PV-induced voltage increase locally. The active power-dependent reactive power control (cosphi(P) control) proofs in some cases to be more effective compared to the voltage-dependent reactive power control (Q(U) control). In the case of the Q(U) control, not all PVs may see a high voltage increase and therefore do not contribute much to the reactive power consumption. As overloading issues are less of a concern (see Figure 53), the cosphi(P) control is therefore more recommended than the Q(U) control;
- The generation cap at 70% of PV capacity is also an effective means to increase PV capacity, albeit not as effective as some of the other measures.

It must be mentioned that some of these mitigation measures are not exclusive from each other but can be applied simultaneously. In particular, the following measures may be applied jointly, in order to achieve a maximum integration of PV into the distribution network:

- Active power-dependent voltage control or voltage setpoint optimization at the primary substation transformer
- Reactive power control with a cosphi(P) characteristic
- Generation cap at 70% or 80% of PV capacity.

With regard to overloading problems, most feeders seem adequately sized to also host high PV penetration levels.

Figure 52: Comparison of maximum PV penetration levels for all mitigation measures, considering voltage violations and a uniform PV distribution

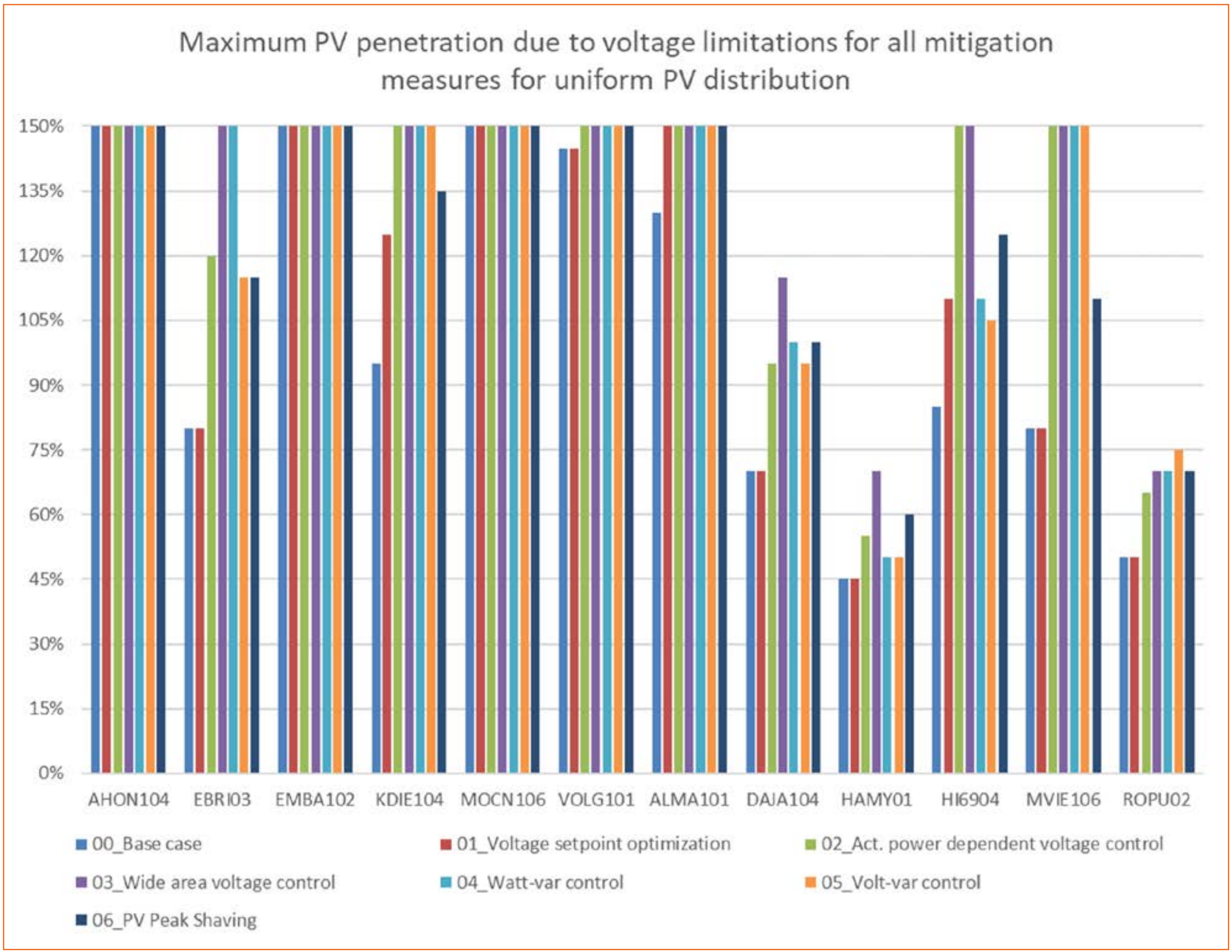
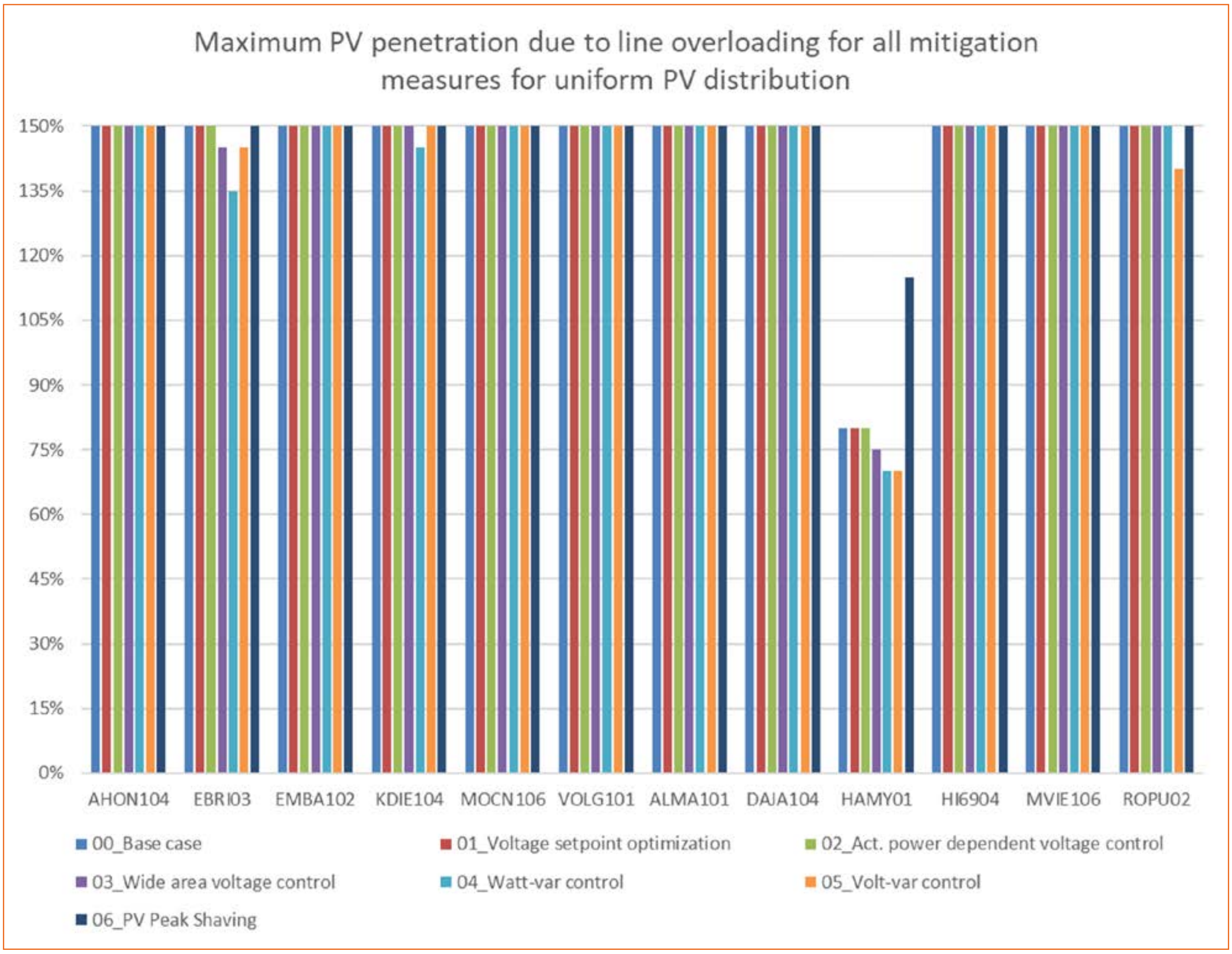


Figure 53: Comparison of maximum PV penetration levels for all mitigation measures, considering line overloading and a uniform PV distribution



9.8.2 Uneven PV distribution

Figure 54 and Figure 55 depict also the results for the uneven PV distribution. Compared to the uniform PV distribution, the feeders show much lower PV hosting capacities. However, also in these cases, voltage problems are much more prominent than line overloading problems. With regard to the effectiveness of the different mitigation measures, a similar picture emerges and further supports the statements of the previous chapter.

In the case of HAMY01, however, the PV hosting capacity can only be increased up to 35%. A combination of different mitigation measures can in this case be more effective and raise the PV hosting capacity further. Otherwise, conventional methods such as line reinforcement may be used to increase PV hosting capacity further, as this feeder is also limited quite severely by line overloading.

Figure 54: Comparison of maximum PV penetration levels for all mitigation measures, considering voltage violations and an uneven PV distribution

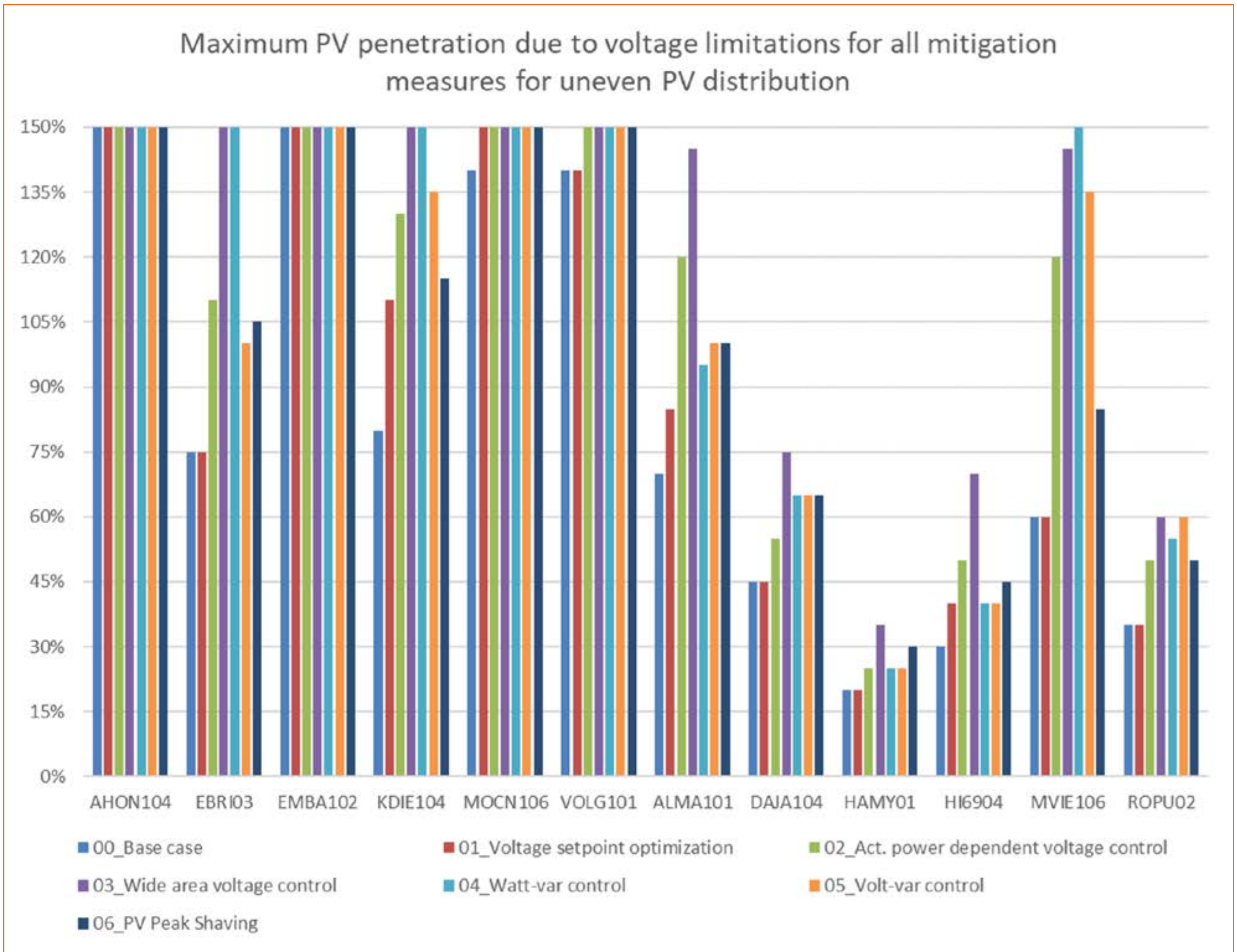
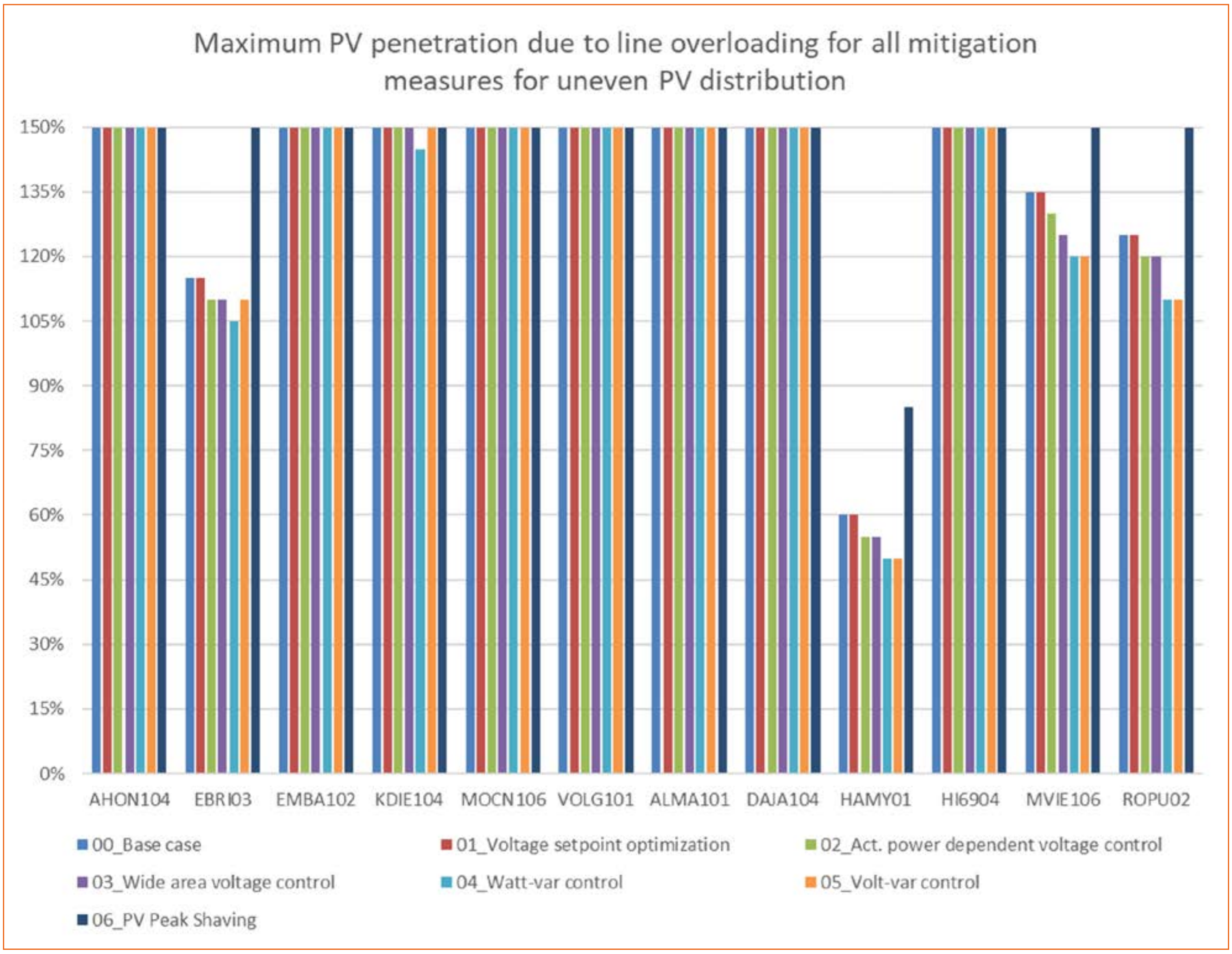


Figure 55: Comparison of maximum PV penetration levels for all mitigation measures, considering line overloading and an uneven PV distribution



10. PROTECTION ISSUES

Apart from overloading and overvoltage issues, also protection issues may arise with a gradual increase of PV power plants in the distribution grid and impact the protection scheme. Typically, during a short-circuit in the distribution, short-circuit current contribution is only provided by the upstream network. However, if PV power plants are present in the distribution network, they may also contribute fault current in the case of a short-circuit.

Depending on the location of the fault and the PV power plant, the fault current contribution may either increase or decrease the fault current. Hence, the protection design must cope with two arising issues:

- Design of equipment: Maximum fault current
  - The equipment must be able to withstand the maximum fault current without being damaged to avoid risk of personnel and loss of investment.
- Design of protection system: Minimum fault current
  - The protection system must selectively and quickly detect a fault and disconnect the affected equipment.

However, compared to conventional power plants, the short-circuit contribution of inverter-based generators such as PV power plants is limited by the inverter rating of the generator.

Hence, as opposed to a conventional generator, where short-circuit current may be 3-5 times the rated current, the fault current contribution of PV power plants is much smaller. However, if other non-inverter-based distributed generation is connected to the distribution network, the higher short-circuit currents should be taken into account.

There are a number of typical issues that can appear in the distribution system with high amounts of distributed generation. Some of them are described in the following chapters as well as common mitigation measures.

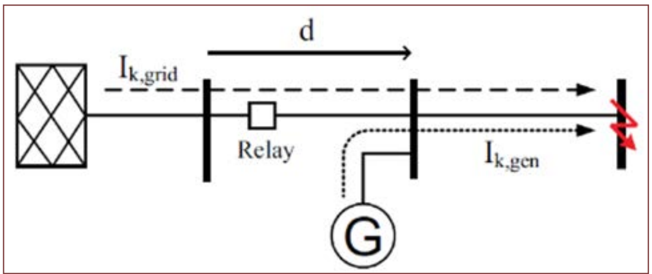
- Blinding of protection
- Recloser issues
- Loss-of-mains detection (islanding detection)
- Sympathetic tripping
- Reduced reach of impedance relays

10.1 BLINDING OF PROTECTION

If the short-circuit is downstream of the PV generator, the short-circuit contribution of the PV results in a reduced short-circuit current through the protection relay. Hence, the short-circuit may stay undetected as the short-circuit current never reaches its pickup value.

This issue is resolved by appropriate inverter settings, disconnecting the PV inverter when a short-circuit (i.e. a voltage drop) is detected. This is already required according to current regulation [8], requiring the distributed generator to disconnect as soon as an electrical disturbance is detected. In this case, after the short-circuit is detected, the PV power plants ceases to contribute to the fault current and the short-circuit is correctly detected by the protection relay. At higher PV shares it should be considered to require fault-ride through capability of the inverters in combination with zero-current mode. In this case, the PV inverter stays connected throughout a fault, but reduces its current contribution to zero as soon as according to its capability and technical requirements. At low to medium PV penetration levels within the country, this capability should only be requested from large-scale inverter-based generation plants. At high PV penetration levels this can also be applied to smaller PV power plants. More details on this matter can be found in the final report of the transmission grid code review report[5] as the fault contribution is also a relevant topic for the transmission grid.

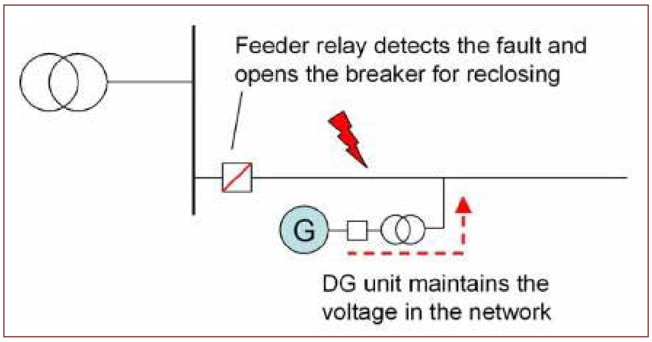
Figure 56: Illustration of the blinding of protection due to PV



10.2 RECLOSER ISSUES

A temporary short-circuit (e.g. a tree branch falling onto the line and burning up) upstream of the PV inverter and downstream of a recloser, as indicated in the following figure, may result in the PV inverter continuing to maintain voltage in the distribution feeder, effectively maintaining the electric arc in the recloser. Hence, the short-circuit appears as permanent to the recloser and the distribution feeder is permanently opened, increasing the outage time. Similar to point 10.1 this is resolved by the direct disconnection of the PV plant during a short-circuit or, alternatively, fault-through capability in combination with zero-current mode.

Figure 57: Illustration of recloser issues due to PV



10.3 LOSS-OF-MAINS DETECTION (ISLANDING DETECTION)

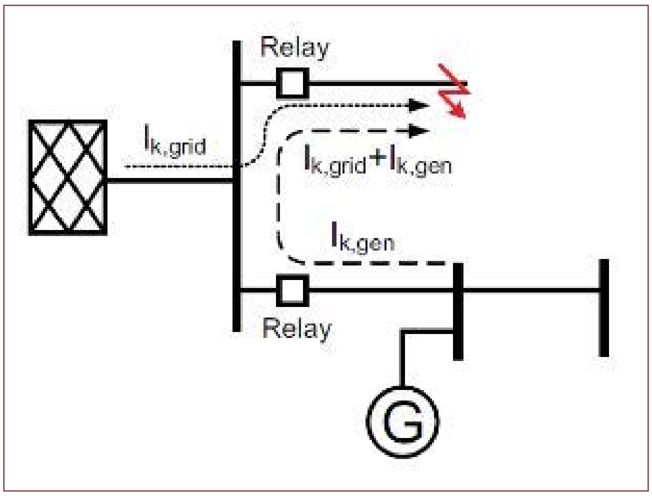
In distribution networks unintentional islanding can appear, when the feeder is disconnected from the upstream network (for example for maintenance) and the PV continues to feed the existing load in the distribution feeder. This may appear in particular if PV and load at this instance is balanced. This may pose a threat to human life if maintenance work is conducted on the line and the line is still energized. Anti-islanding protection is therefore required for PV inverters. Such is also the case according to Dominican regulation [8].

5 This report is currently being drafted and is expected by the end of 2020. The official name of the project is "Revision of the network codes of the Dominican electricity system".

10.4 SYMPATHETIC TRIPPING

A short-circuit in an adjacent feeder to the PV plant may result in a short-circuit contribution of that PV inverter that exceeds the pickup value on the healthy feeder (where the PV is connected). This may result in the healthy feeder tripping before the actual fault is cleared. If this issue appears it can be resolved through better parametrization of fault clearing times of protection relays or directional overcurrent protection. This is however an issue rarely seen and usually other factors limit the PV penetration much earlier before this issue appears. This is for example also evidenced by [9] where sympathetic tripping was evaluated not to be an issue for 16 representative feeders in California.

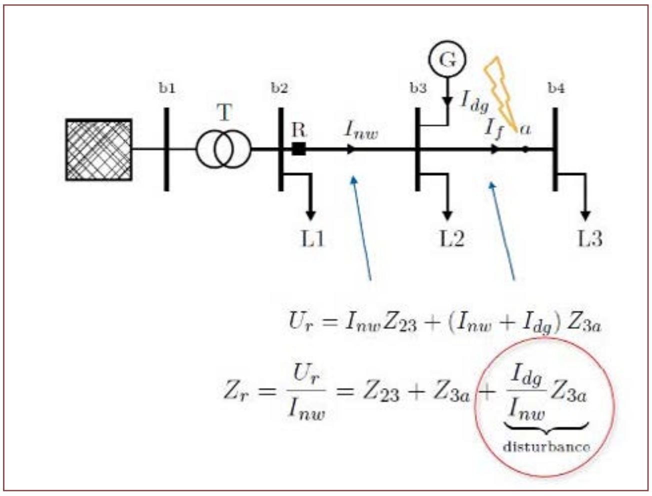
Figure 58: Illustration of sympathetic tripping due to PV fault current



10.5 REDUCED REACH OF IMPEDANCE RELAYS

In case impedance relays are used as protection system, the short-circuit contribution of the PV inverter reduces the active area where a short-circuit is detected. Through increased sensitivity of the relay, the active area can be increased, however, reducing selectivity. Otherwise, additional protection relays can be used. In [9], however, this was only analysed to be an issue in feeders where line regulators were also in place, while most feeders were not significantly impacted by this.

Figure 59: Illustration of a reduced reach of impedance relays due to PV



11. CONCLUSIONS AND TECHNICAL RECOMMENDATIONS

11.1 GENERAL CONCLUSIONS AND RECOMMENDATIONS

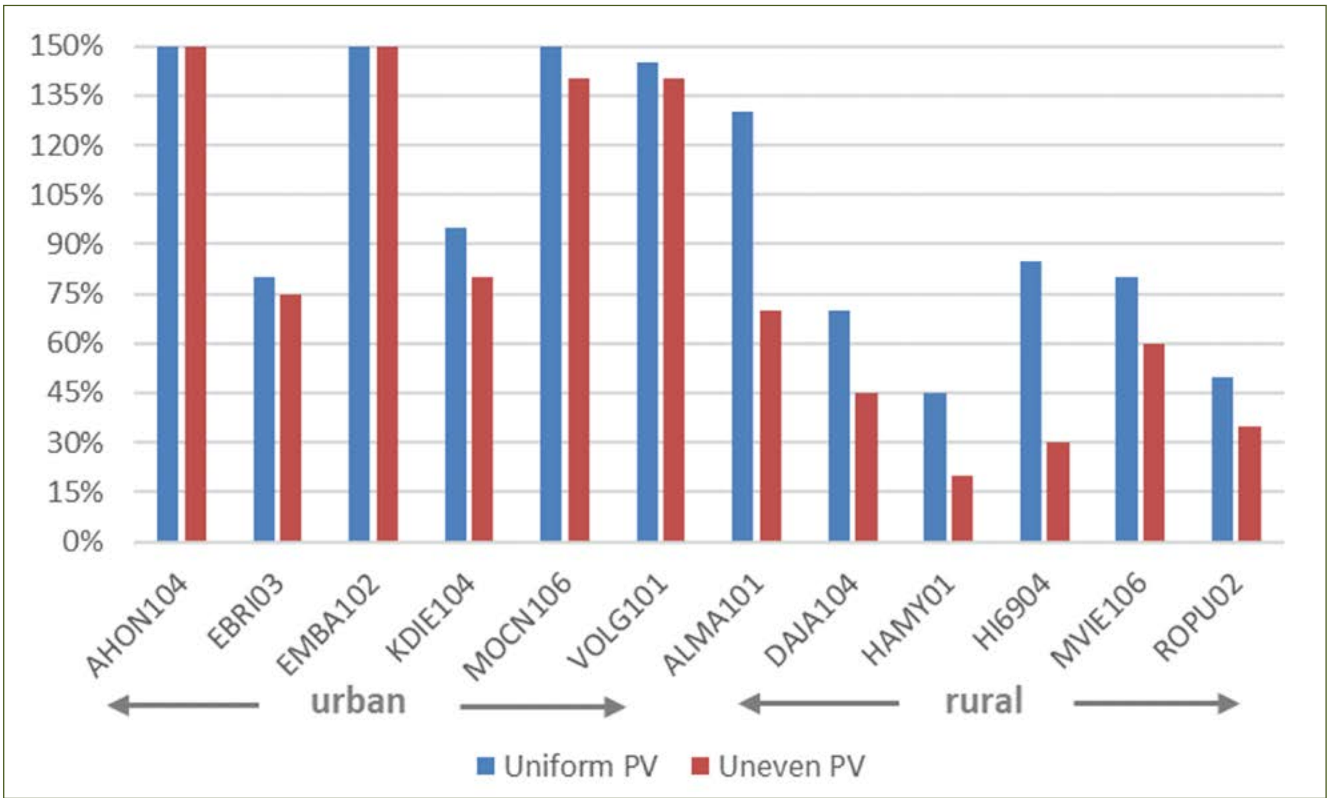
Simulation results from the twelve feeders show that PV penetration levels may vary widely amongst the different feeders. Within the study, feeders with extreme feeder characteristics have been chosen deliberately in order to find safe limits or minimal PV penetration limits, at which PV integration can be considered as unproblematic. At the same time, the goal of the study was to show more commonly found feeders and which typical PV penetration limits apply in these cases.

The feeders with extreme characteristics, in particular the feeder HAMY01, show that there are some specific feeders that have lines branching far off from the primary substation and showing very low voltage levels and line overloadings during peak demand. These weak distribution feeders are therefore also strongly limiting PV integration, as in particular overvoltages due to PV infeed may arise quickly. In the case of HAMY01, maximum PV penetration levels were determined to be only 20% in the uneven PV distribution scenario and 45% in the uniform PV distribution scenario.

Most other feeders, however, show very high PV hosting capacities, even above the highest simulated PV penetration level of 150%. This shows the significant untapped potential for PV integration in Dominican distribution feeders. In particular urban feeders are typically stronger than rural feeders and only have short branches, with a maximum distance from the primary substation often being below 10 km. In these cases, voltage problems are much less likely to occur and maximum PV penetration levels could be increased by a multitude.

A summary of obtained maximum PV penetration limits can be seen in Figure 60.

Figure 60: Maximum PV penetration levels of the 12 distribution feeders for both a uniform PV distribution and an uneven PV distribution



Regarding protection issues, some of the arising issues are already solved through state-of-the-art inverter capabilities, disconnecting the PV inverter in the case of a short-circuit (already required by Dominican regulation) or switching to zero-current mode while staying connected (possible improvement in future distribution grid code revisions). Other capabilities such as anti-islanding protection are also already required by Dominican regulation and common standards, reducing the associated risks. Some protection issues remain, for example the possibility of sympathetic tripping or the increment of short-circuit current above the limits of the protection relay. However, as the fault current from PV inverters is limited by the inverter rating, such issues are unlikely to occur at lower PV penetration levels and can in most cases be fixed by better parametrization or, if necessary, upgrade/replacement of some protection relays. These measures are considered to be much less cost-intensive than problems arising from overvoltages or line overloading and should therefore not be considered as limiting factors for PV integration.

To find a more accurate constraint for PV penetration limits, a hosting capacity analysis should be conducted once the current PV penetration limit is reached. Chapter 12 describes in detail the recommendations for the interconnection process in order to establish such feeder hosting capacity analyses in the regulation.

As has been shown, higher PV penetration limits can in many cases be lifted. This is also evidenced by PV penetration limits in some of EdeNorte's distribution feeders, where PV penetration levels up to 114% have been installed. This can be seen in Table 5, which shows the feeders with the highest PV penetration levels above 15% of peak demand.

Table 5: PV penetration levels above 15% of peak demand in the case of EdeNorte. Penetration levels are in some cases considerably higher than the regulated 15% limit.

CIRCUITO	POTENCIA MÁXIMA	KW INSTALADA	%
PIME102	876,13	998,08	113,9
MCRl103	730,78	526,5	72,05
RINC103	1326,88	870,71	65,62
MAON102	5 482,32	2 367,36	43,18
CANA106	7 523,81	3141,12	41,75
APPL101	1436,32	542,75	37,79
SOSU101	3 388,49	1 020,12	30,11
VOLG101	12461,72	3 380,48	27,13
CHIV101	12 791,43	2298,55	17,97
CHIV104	4889,47	746,38	15,26
RINC102	3 653,00	552,07	15,11

11.2 PERFORMANCE OF TECHNICAL MITIGATION MEASURES

Most mitigation measures were able to significantly increase the maximum PV penetration levels, in particular improving any PV-induced voltage problems.

11.2.1.1 Voltage control at the primary substation

The first three measures (HV/MV voltage setpoint optimization, active power-dependent voltage control of the HV/MV transformer and wide area voltage control) aim all at an improved operation of the automatic tap changer at the primary substation. Common step-down transformer have the capability to enable the second option, an active power-dependent voltage control that utilizes the locally measured power flow to regulate the voltage, in particular lowering the voltage when large reverse power flows are measured. If this option is available, it can be considered as much more effective as an adjustment of the voltage setpoint (mitigation measure 1) and much cheaper than a wide area voltage control (mitigation measure 3). Hence, to increase significantly PV penetration limits this may be a suitable possibility.

11.2.1.2 Reactive power control by PV inverters

Furthermore, the possibility to set reactive power characteristics at the PV inverters should be enforced by an updated distribution grid code or as part of the interconnection process, at least for larger PV inverters (e.g. above 5 kW). Reactive power control is a capability that most inverters on the market can fulfill already and common international grid codes require PV inverters to have the capability to set either a non-uniform power factor, a cosphi(P) characteristic (watt-var) or a Q(U) (volt-var) characteristic. At the installation of the PV inverter, the distribution system operator may then freely choose if he wants to utilize one of these options or if the PV inverter should operate at uniform power factor. This decision should be based on the characteristics of the distribution feeder and if voltage issues are a concern. For the PV plant owner, the reactive power control typically does not result in any extra costs.

11.2.1.3 PV generation cap of the inverter at 70% or 80% of installed PV panel capacity

Lastly, a further option to reduce the impact from PV power plants on the distribution grid is to cap the PV inverter at 70% or 80% of the installed PV panel capacity. In most countries, a cap of the PV feed-in at 70 – 80% of the maximum value results in losing only 2 – 4% of annually produced PV energy, as peak PV output is only reached during few hours with blue skies and often reduced by dust and temperature effects.

The PV inverter size is the crucial parameter for the distribution system operator to determine the maximum impact from the PV plants in a distribution feeder. Hence, also this type of information should be collected through data sheets during the PV installation and used in the DSO's planning studies on the PV impact. In Germany, it is also common practice to set an even stricter PV cap at 60% or even 50% and couple this with an incentive on battery deployment. In this configuration, the battery is incentivized to be charged with PV energy during peak output, as otherwise this energy production is lost due to the PV cap. This essentially provides a possibility to incentivize battery behavior that provides peak shaving of PV generation, as opposed to a battery that is charged as soon as a PV generation exceed the local load which may not alleviate PV infeed during peak generation.

11.2.4 Combination of different mitigation measures

The mitigation measures from section A to C can be combined, in order to have a maximal increase of PV hosting capacity. The most cost-effective combination in such a case would be:

- The active power-dependent voltage control at the primary substation transformer;
- Reactive power control of the PV inverters through a cos-phi(P) characteristic; and
- A PV generation cap of the inverter at 70% or 80% of installed PV panel capacity.

12. RECOMMENDATIONS ON THE INTERCONNECTION PROCESS

The 15% limit as a share of peak demand is a regulation that was most likely adopted from US regulation. In the US, the 15% limit was established in 1999 by the California Public Utilities Commission (CPUC) and later adopted by the US Federal Energy Regulatory Commission (FERC) [10]. The rationale behind the 15% rule resulted from an average minimum demand of 30% in US distribution feeders. Taking a safety margin of 50% for the minimum load, the resulting limitation was put at 15%. This was meant to prevent any type of reverse power flows and the subsequent impacts on unintentional islanding, voltage deviations, protection miscoordination, and other potentially negative impacts.

This 15% limit has been used as a model by many US states for their interconnection process but has since then gone through multiple revisions. In particular, this 15% limit is not a hard limit, disallowing higher penetration levels, but rather a soft limit after which supplementary studies should be conducted.

In a 2012 revision, additional filters were added to the 15% rule, in order to allow for higher PV penetration levels without conducting a detailed study. These supplemental review processes use for example a Minimum Load Screen, which checks if the aggregated PV capacity is below 100% of minimum load. If this is the case, the PV penetration limit may also be lifted above 15%.

The exact specifications of the screening process can be found for example in California Rule 21 [11] and Hawaiian HECO Rule 14H [12]. Currently, these screening processes are undergoing further revision processes to increase the limit and/or define further filters for feeders, where a higher penetration level is possible. For example, on the Hawaiian islands under certain conditions PV penetration levels of up to 250% of minimum demand are already allowed [13].

A proposal for replacing the 15% limit with a method based on hosting capacity analysis is currently examined by the Californian public utilities commission (CPUC) in the US [14].

12.1 NREL RECOMMENDATIONS

The US National Renewable Energy Laboratory (NREL) has drafted a short recommendation report on improving the criteria for the interconnection process. Figure 61 shows a summary of the most relevant shortcomings within the Dominican interconnection process and which recommendations should be applied.

The recommendations highlight the main current practices in the US during an interconnection process. Therefore, they form a good starting point for the improvement of the Dominican interconnection process. However, the recommendations within the report at hand go a step further by taking current discussions and practices in the interconnection processes in California and Hawaii (which are the most advanced in terms of PV development in the US) into account as well as experiences from countries outside North America.

It is recommended to keep a close eye on the anticipated updates of the interconnection process in California [14] to align and adopt any relevant good practice.

Figure 61: Main differences between the Dominican Republic's interconnection regulations and the best regulatory practices for distributed generation interconnection [15]

No fast track process for ~10 kW systems	• It is important not to create unnecessary queues for residential systems
No summary filters are defined, but a detailed study is directly required	• No minimum demand during the day for the limit of penetration as an alternative
No voltage level penetration limits are defined for systems > 250 kW	• The number or aggregate capacity of systems > 250 kW per circuit can be limited, without affecting residential solar roofs
No grouping of generators requiring detailed studies and system improvements is offered	• The cost of the detailed study can be divided among a group of requests with nearby location
No improvements are considered based on a recommended series of improvements to the distribution system	• International regulations contain a list of improvements that distributors should consider, for example changing the tap changer reference point of the transformer or the control of the capacitor
Smart inverters are not used for all or only those applications that fail simple and supplementary interconnection filters	• Activation of volt-var and volt-watt mode guarantees local support for voltage control without additional costs to the consumer

12.2 IMPROVEMENTS TO THE 15% OF PEAK LOAD LIMIT

Currently, the regulation requires that a new supplementary study is conducted for every PV system that exceeds the 15% of peak load limit of the distribution feeder. The additional cost for such a study provides a barrier for the deployment of further PV systems, in particular for small-scale PV systems where the cost is disproportionally high. It further creates a backlog of studies on the DSO side, as he needs to process a large number of studies through the applications above the 15% limit.

Further, the study at hand shows that this limitation is technically unjustified as the majority of feeders shows the potential for significantly higher PV penetration levels. Therefore, such limit would unnecessarily restrict distributed PV development within the country.

Thus, the following recommendations are suggested to replace the 15% limit, with a justification for each respective recommendation in the table thereafter:

	Recommendations
(1)	For **rural feeders as well as feeders below a voltage level of 12.47 kV**, increase the initial limit to **25% of peak demand or 100% minimum daytime demand** (between 10 am and 3 pm) of the respective feeder, whichever is higher.
(2)	For **urban feeders at or above a voltage level of 12.47 kV**, increase the initial limit to **50% of peak demand**.
(3)	**Inverter equipment** must be capable of operating at a **power factor ≥ 0.9 (lagging and leading)** and the operation modes **constant power factor, volt-var (QU)), and watt-var (Q(P))**. The used operation mode is the decision of the DSO and may be changed.[6]
(4)	It is the **responsibility of the DSO to optimize network operation** in order to ensure the initial hosting capacity limits from recommendation (1) and (2).

	Justifications
(1)	Even extreme feeders with uneven PV distribution show at least a 25% hosting capacity with mitigation measures such as voltage setpoint optimization or reactive power control in place. Only one feeder with a voltage level below 12.47 kV was analyzed, therefore urban feeders at voltage levels below 12.47 kV should also be treated conservatively with an initial hosting capacity limit of 25% of peak load. The limit of 100% daytime minimum demand is an alternative supplementary limit applied in the US. [11]
(2)	The simulations showed, that even at uneven PV distribution at least a 50% hosting capacity is feasible, without applying any mitigation measures such as voltage setpoint optimization or reactive power control. However, due to uncertainties with other urban feeder characteristics, the initial limit is not set higher than 50%. It is the responsibility of the DSO to check particularly exceptional feeders that they are also not negatively impacted by the PV penetration levels.
(3)	Reactive power control has a significant impact on the feeder hosting capacity as shown in the simulation results. Similar reactive power capabilities as well as reactive power modes are enforced through grid codes in most European countries, US, Australia and other countries worldwide as well as specified in standard such as IEEE 1547-2018 [16]. Further advanced inverter capabilities are described in chapter 12.6 and should be required as well.
(4)	At unoptimized network operation, very few feeders with extreme feeder characteristics may experience problems at lower PV penetration levels than the initial screen. However, as analyzed in this study, these can be mitigated by network optimization measures like reactive power control or voltage setpoint optimization. Therefore, for extreme feeder characteristics (e.g. feeders with very long single-phase lines) the DSO should utilize these network optimization measures to ensure the initial hosting capacity limit without the need for expensive distribution upgrades. Suitable network optimization measures are mentioned in recommendation (7).

6 The technical requirements for distributed generators need to be specified in the distributed generator interconnection regulation. Further technical requirements are specified in chapter 12.6.

12.3 RECOMMENDED PROCEDURES IF INITIAL LIMIT IS BREACHED

The initial limit from the previous chapter provides the minimum PV hosting capacity limit. Below this, only at very rare and exceptional cases negative impacts from PV are expected.

However, most distribution feeders will have a penetration level that is still significantly higher than the proposed elevated limit to 25% or 50% of peak load, depending on the respective feeder type. Therefore, a procedure should be set up to accurately increase a feeder's hosting capacity until the actual technical limits are reached.

The following recommendations are suggested to set up this procedure:

	Recommendations
(5)	When the **current maximum PV penetration limit is breached or close to be breached**, the **DSO conducts a hosting capacity analysis** of the distribution feeder, taking into account the current distribution of PV systems in the feeder. This analysis determines a new maximum PV penetration limit, by taking whichever of the following two cases is less: • **Results from the hosting capacity analysis minus a safety margin of 5% of peak demand** • **Previous hosting capacity limit increased by 20% of peak demand**[7] It should be considered to express the new hosting capacity limit as a fixed MVA value, instead of a value relative to the peak demand.
(6)	The new maximum PV penetration limit is determined by scaling up the current PV distribution. In justified reasons, different assumptions may be taken to scale the PV capacity. Optional: A review committee may be set up that reviews hosting capacity analyses and sets requirements on assumptions (see also next chapter). The committee should be formed by relevant stakeholders from the DSOs, regulatory body, PV developers and associations, university and external consultants.
(7)	If the hosting capacity analysis results in **no further increase of PV capacity**, the DSO must **investigate and apply network optimization measures** to increase the hosting capacity. These include: • Utilizing reactive power control of PV inverters to reduce overvoltage (chapter 9.4, recommendation (3)) • Optimizing the voltage setpoint at the primary substation (chapter 9.1) • Applying active-power dependent voltage control at the primary substation (chapter 9.2) • Optimizing capacitor control
(8)	If the **hosting capacity cannot be further increased by utilizing network optimization measures**, the DSO should investigate **distribution upgrade options** (e.g. chapter 9.3 and 9.7) to increase the hosting capacity. The **PV applicant should be informed** about the results of the hosting capacity analysis and the cost of the distribution upgrades. Further, he should be put on a **waiting list** and a recurring evaluation process should be started to determine if the PV applicants are willing to pay for the distribution upgrade, with **costs shared amongst PV applicants** according to their interconnection equipment capacity, i.e. the inverter capacity.[8]
(9)	**Publish the hosting capacity studies** for each feeder on a website, to be consulted by PV applicants and other interested organizations to ensure transparency.

7 Check the example in chapter 12.8 for further explanation

8 A similar process is currently discussed in California [14]

	Justifications
(5)	To increase the maximum PV penetration level for a feeder, an iterative process is started, increasing the PV penetration level in increments of 20% until the technical limitation is reached, determined by the hosting capacity analysis. A 5% safety margin is provided in the hosting capacity analysis, in order to account for a potentially unfavorable distribution of any further installed PV capacity and uncertainties of simulation results. As the peak load is changing over time, it may make sense to only define the initial hosting capacity limit in relation to peak demand, and use fixed values in MVA as subsequent hosting capacity thresholds. This avoids uncertainty on the DSO side, when hosting capacity is close to technical limits and peak demand is increasing, as the hosting capacity is not necessarily increased alongside with the increasing peak demand. It also reduces the administrative burden to continuously update hosting capacity limits, as they are changing with growing demand.
(6)	Since the PV penetration level is increased at maximum in increments of 20%, it is expected that the distribution of further installed PV capacity will typically be similar to the existing PV distribution. Exceptions can however for example arise, if the existing PV distribution is made up by few larger installations between 250 kW and 1 MW. Further, there can be some ambiguity in the assumptions taken for the hosting capacity analysis results, therefore the analysis results should be made transparent to the PV applicant (see recommendation 9) and it may be advisable to have a review committee that discusses these assumptions taken and has the authority to prescribe adjustments to the hosting capacity analysis process.
(7)	The DSO has a number of optimization measures available that do not require any distribution upgrades and therefore do not incur any additional cost on the DSO side, therefore, such network optimization measures should be utilized before distribution network augmentation.
(8)	The most cost-efficient distribution upgrade measures to increase the hosting capacity should be investigated. The costs due to these distribution upgrades may be very high but if distributed over a larger number of PV applicants, they can still be realized, enabling higher PV penetration levels as well as compensating the DSO for the network augmentation cost.
(9)	It is important to make the study results transparent to PV applicants, so that any objections to PV installations are justified.

In feeders, where voltage problems may be expected in the future at higher PV penetration levels, it is the responsibility of the DSO to proactively select the most suitable reactive power mode during commissioning, so that he does not have to change settings retrospectively by costly field visits. This is not required if the inverter is connected via communication and the settings can be changed remotely, allowing the DSO to change settings flexibly according to the needs for the respective distribution feeder.[9]

Chapter 12.8 illustrates the proposed interconnection process including the process to determine the feeder's hosting capacity and explains the process using an example..

12.4 PLANNING GUIDELINES FOR PV HOSTING CAPACITY STUDIES

To reduce ambiguity in the PV hosting capacity studies, it may be advisable to set guidelines and assumptions also in the interconnection process document. These guidelines and assumptions may be reviewed and changed by a review committee, as suggested in the previous chapter. They may also change over time, as new issues may become apparent or other issues are resolved through new inverter capabilities.

9 In some power systems, there are additional requirements for the reactive power range or power factor at the primary substation. Reactive power consumption from PV inverters influences this, hence, regulation should be updated in these cases to reflect this.

The following planning guidelines are recommended to be set up:

	Recommendations
(10)	For steady-state overvoltage limitations, the maximum voltage in the MV network must be kept below **1.07 p.u. (rural feeders) or 1.045 p.u. (urban feeders), leaving a 3% voltage range on the LV network** (see recommendation (13)).[10]
(11)	**Loading limitations of conductors and transformers of 100%**
(12)	If the PV impact on **short-circuit currents and protection equipment** limits the hosting capacity, the DSO shall investigate network optimization measures to increase the hosting capacity. If the optimization measures are not sufficient, he may require new inverters in that distribution feeder to be certified according to standards that limit the impact of PV on the short-circuit current and protection equipment.

	Justifications
(10)	In this case, it must be ensured that the voltage increase in LV networks does not exceed 3%. Hence, an additional limit is required that is discussed in chapter 12.5.
(11)	To leave a safety margin, also lower values of 80% or 90% may be set.
(12)	Potential network optimization measures include better protection parametrization or different protection schemes. Where no suitable options are available, advanced inverter capabilities can be required. For example, inverters that comply with category III of IEEE 1547-2018 [16] must reduce their PV output to zero within 83 ms after a grid-fault. Also all LV-connected inverters in Germany must already reduce their PV output to zero within 60 ms according to German regulation [17].[11]

12.5 FURTHER INTERCONNECTION PROCESS IMPROVEMENTS

The following further improvements are recommended to be included in the interconnection process:

	Recommendations
(13)	**Additional screen for ΔU < 3% voltage criterion in LV networks:** The new PV system including the aggregated existing PV capacity in the same LV network may not increase the voltage by more than 3% between distribution transformer LV side and PV connection. The following formula may be used (see also chapter 6.3): $$\Delta u\,[p.u.] = \frac{S_{PV}[VA] \bullet (R_{line}[Ohm] \bullet \cos(\varphi) - X_{line}[Ohm] \bullet \sin(\varphi))}{3 \bullet U^2[V]}$$
(14)	**Abolish** the current regulation, to limit the aggregated system capacity in a feeder to 1% of total maximum system demand. It should be specified under which circumstances the transmission system operator may limit the amount of distributed generation in a specific area. The restrictions must be technically justified and options for mitigation must be analyzed.
(15)	Define **clear deadlines for hosting capacity studies.**
(16)	Define **clear definitions for rural and urban feeders** to avoid ambiguity.
(17)	Recover the **additional cost of hosting capacity studies through slightly increased application costs or other suitable cost recovery options,** with the aim of distributing the additional cost for hosting capacity studies across all PV applicants.
(18)	Improve capabilities of DSOs to use **power system analysis software** and perform hosting capacity analysis.
(19)	Optional: Locational Value Maps (LVM) may be established. These are online maps that can be consulted by the PV applicant to check how much more hosting capacity is available in the area where he intends to install a PV system.

10 It should be discussed if the voltage range in urban feeders can be increased from 0.925 – 1.075 p.u. to 0.9 – 1.1 p.u. allowing for more flexible voltage operation, hence significantly increasing PV hosting capacity. This would also better align with international good practice, which typically does not differentiate between voltage thresholds in urban and rural distribution networks.

11 Alternatively, Dominican regulation may specify that such requirements are applicable to all inverters in one of the next revisions of the interconnection process.

	Justifications
(13)	By clearly limiting the available voltage band to 3% in the LV network, the full voltage band up to 1.07 p.u. (rural feeders) or 1.045 p.u. (urban feeders) can be utilized in the MV network. Otherwise, a single PV plant that results in a voltage increase of 5% in the LV network will unnecessarily constrain the MV voltage band and, hence, PV capacity in other LV networks. The calculation requires limited topological information on line lengths and types, and is also used in German regulation [17]. The ability of the inverter to reduce the voltage through reactive power consumption is taken into account in the formula. If the 3% criterion is breached, a supplementary study should be carried out to find a suitable mitigation measure (e.g. line upgrade, new line, or limiting PV power).
(14)	Limiting the aggregate system capacity to 1% of total maximum system demand significantly inhibits PV development without technical justification. Any such limitations should either be abolished or be technically justified from calculations by the transmission system operator or independent system operator in the case of isolated systems (e.g. CTSPC), as they will typically depend on the transmission and system needs.
(15)	Clear deadlines should be defined for conducting the hosting capacity studies as well as for informing the PV applicant on its application evaluation, in order to not create a backlog of PV applications. Reducing the deadlines requires the DSO to conduct the study before the current maximum PV penetration limit is reached, which does not have a large impact on the validity of hosting capacity results. Stringent deadlines are also common in other power systems, giving the applicant the possibility to sue if deadlines are not kept.
(16)	It should be clear which feeders are considered as urban feeders and which as rural feeders, when determining the initial hosting capacity limit.
(17)	Since the hosting capacity studies would replace supplementary studies and would not be attributable to a single PV applicant, it is recommended to cover the additional costs through the application costs. However, since only a fraction of studies needs to be conducted in comparison with the large amount of supplementary studies, it is expected that the resulting cost and burden for the DSO are significantly reduced, even if the study requires more in-depth analysis. Suitable cost recovery solutions should be discussed between the DSOs and the regulator.
(18)	Typically, distribution system operators are managing the data on their MV network structure in a Geographic Information System (GIS). An automatic import from such GIS systems into power system analysis software such as DIgSILENT PowerFactory is possible through appropriate interfaces which can enable the DSO to receive an up-to-date network model of the distribution feeder. This naturally requires information on the GIS system to be up-to-date as well as accurate information on PV allocation to distribution transformers. Typical import options for example in DIgSILENT PowerFactory can be performed through a DGS import, which was also used in the case of EdeEste for this study. Additional guidelines to conduct interconnection studies are also provided in IEEE 1547.7-2013 [18].
(19)	In Hawaii, the system operators of the individual islands already provide such Locational Value Maps (LVM) for customers. [19]

12.6 SMART INVERTER REQUIREMENTS

In the current interconnection process document it remains unclear, which exact specifications inverters need to follow under the current regulation. Reference is made to the IEEE 1547 and UL 1741 standards but it remains also unclear which versions of the standards should be followed.

In particular recent revisions of these standards, such as IEEE 1547-2018 [16], IEEE 1547.1-2020 and UL 1741 Supplement A (SA) specify advanced inverter capabilities and testing procedures that are essential for power system reliability and increasing the hosting capacity of variable renewable energy in the power system.

California and Hawaii have led the way in developing these standards in the US. In particular Hawaii already experiences high penetration levels of inverter-based generation, with the largest contributing technology being small-scale solar PV installations. The most populous island Oahu has a peak demand of about 50% of that of the Dominican Republic and 10% of generation is currently coming from small-scale PV [20]. This results in many distribution feeders on Oahu having PV penetration levels above 250% of minimum load. For these reasons, the state serves as a good reference for developments in the Dominican Republic and important lessons can be learned.

Due to the increasing amount of PV, the electric utility Hawaiian Electric Industries Inc. had to retroactively change and widen frequency and voltage ride-through settings from legacy inverters as these inverters were contributing to a large share of capacity and would have disconnected at the same time during a larger frequency or voltage excursion [21]. The communication capability of legacy inverters from one of the manufacturers dominating the market on the islands allowed to do the process remotely for the majority of inverters (800,000 inverters within 2 days [22]) which otherwise would have been much more expensive. In Germany, the same issue was found already in 2005, with 200,000+ inverters being retrofitted for a cost of more than 170 million € [22].

Therefore, it is highly recommended to require some of the inverter capabilities early on, e.g. by adopting already the most up-to-date IEEE 1547 revisions or equivalent standards where available. Inverters should be certified according to these standards. Existing lists of certified equipment in Hawaii or California can in part be adopted.[12] The inverter should only be required to comply with the inverter capabilities stipulated during commissioning and not with the inverter capabilities specified in newer versions of the distributed generation interconnection regulation. Otherwise, PV inverters would potentially need to be retrofitted during a periodic test, resulting in uncertainty on the side of the PV applicant.

Table 6 specifies recommendations on advanced inverter capabilities that are currently not required in the Dominican Republic. Requirements should be periodically (approx. every 2-3 years) reviewed to reflect system requirements with growing variable renewable energy penetration levels and latest advancements in inverter capabilities.

Table 6: Recommended advanced inverter capabilities as well as suggestions for responsibility of defining default settings (see also additional information in chapter 2.2)

INVERTER CAPABILITY	RECOMMENDED?	RESPONSIBLE FOR DEFINING DEFAULT SETTINGS[13]
Low/high frequency ride-through (chapter 2.2.1.1)	Highly recommended	ETED
Response to frequency deviations / frequency-watt mode (chapter 2.2.1.2)	Highly recommended	ETED
Low/high voltage ride-through (chapter 2.2.3.1)	Highly recommended	ETED
Reactive power capability (chapter 2.2.2.2)	Highly recommended	EDE
Reactive power control modes (constant power factor, volt-var (Q(U)), watt-var (Q(P))) (chapter 2.2.2.2)	Highly recommended	EDE
Active power control modes / volt-watt mode	Optional	EDE
Ramp rate limitations	Optional	ETED
Communication capability (chapter 2.2.4.1)	Recommended above defined size	ETED/EDE

More information on these topics was also described in chapter 2.2.

12 See Hawaiian certified equipment list: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/qualified_equipment_list.pdf or Californian certified equipment list: https://www.energy.ca.gov/programs-and-topics/topics/renewable-energy/solar-equipment-lists

13 In the case of small isolated systems, the independent system operator should specify these settings.

12.7 ALTERNATIVE OPTIONS FOR INTERCONNECTION PROCESS IMPROVEMENTS

12.7.1 Lifting the 15% limit based on technical feeder characteristics

Instead of conducting hosting capacity studies, an alternative option could be the use of simple formulas to calculate the approximate PV penetration limits based on the most important technical feeder characteristics.

Potential candidates for the most important feeder characteristics that play an important role in determining the maximum penetration level are as follows:

- Maximum feeder distance from the primary substation (may also be labelled as "feeder length" as opposed to the "aggregated feeder length")
- Average resistance and reactance on the trunk conductor or on the feeder section leading to the point in the system with the largest distance from the primary substation. This indicator may be unsuitable in feeders that have multiple long branches, which may particularly be the case in rural areas.
- Share of three-phase lines in comparison to the aggregated line length
- Factors describing the inhomogeneity of load distribution within the feeder

However, a formula that successfully achieves to capture different feeder characteristics and covering exceptional cases is difficult and requires to be verified by a large number of feeders. The lower number of feeders within this study was not able to derive such formula with high certainty, which would severely underestimate actual PV hosting capacities. Therefore, this option was not further pursued.

Also in the US, similar approaches were suggested by NREL [9], [23], [24] but have never been adopted. Instead, hosting capacity studies seem to be the way forward and will likely be adopted in future revisions of interconnection requirements. [14]

12.7.2 Shallow connection charge scheme and interconnection process experience in European countries

Compared to the US, the experience with distributed generation in distribution feeders is very different in European countries. In most European countries, costs for distribution grid upgrades are typically born by the distribution grid operator and compensated through network charges that are part of the consumer's electricity bill.

This scheme is typically called "shallow connection charges" as opposed to "deep connection charges" which is the system applied for example in the US and the Dominican Republic, where costs for grid upgrades are born by the applicant. Also mixed systems exist, with e.g. costs for LV network upgrades born by the applicant and costs for MV network upgrades born by the DSO.

The scheme of shallow connection charges removes the regulatory barrier of a 15% limit and instead shifts the responsibility to the DSO to accurately determine the maximum PV penetration limit and the assessment at which point he needs to reinforce the distribution feeder or find other measures to mitigate the impact from distributed generation. The network fees are typically regulated by the energy regulator of the respective country and are set up in such a way to provide an incentive to keep the costs for network reinforcements on the DSO's side as low as possible.

The clear advantage of shallow connection charges is that they remove the regulatory complexity to find appropriate thresholds on maximum PV penetration levels and foster the growth of distributed PV generation. The disadvantage is that the locational pricing signal from the deep connection charges is lost, resulting in too much PV installations in some areas, which increases local distribution upgrade costs and therefore total system costs, as PV is not installed in areas where sufficient capacity is available.

This makes it difficult to provide good practice examples from European perspective, however, the scheme of shallow connection charges may be discussed as an alternative approach in order to remove regulatory barriers for PV deployment.

12.8 SUMMARY OF INTERCONNECTION PROCESS RECOMMENDATIONS

Figure 62 and Figure 63 show an updated interconnection process as well as the proposed process to determine the hosting capacity limit with the recommendations as suggested in chapter 12.2 to 12.6.

Finally, for better illustration an example is given in the following to describe the process of determining a feeder's hosting capacity limit:

- Feeder ABCD101 is a rural feeder. The initial hosting capacity limit is set to 25% of peak demand / 100% of minimum daytime demand.
- It is expected that voltage problems will become an issue, therefore new PV power plants are operated in volt-var mode.
- PV capacity surpasses the threshold. The DSO conducts a hosting capacity study.
- Hosting capacity results show significant improvement greater than 20%. Hosting capacity limit is increased by 20%.
- PV capacity surpasses new threshold of 45% of peak demand. New hosting capacity study.
- Hosting capacity results show improvement of 15%. Hosting capacity limit is increased by 10%, keeping the safety margin of 5%.
- PV capacity surpasses new threshold of 55% of peak demand. New hosting capacity study is conducted including network optimization measures.
- By using volt-var (Q(U)) control at the inverters and optimizing the voltage control at the primary substation the hosting capacity can be improved by 10%. To keep the safety margin of 5%, the hosting capacity limit is increased by 5%.
- PV capacity surpasses new threshold of 60% of peak demand. New hosting capacity study is conducted including cost-efficient distribution upgrades.
- Line upgrades would result in a hosting capacity improvement of 20%.
- PV applicants are put on a waiting list.
- At some point, PV applicants decide to pay for distribution upgrade.
- Distribution upgrade is carried out and hosting capacity results are updated. New hosting capacity limit is increased by 15% (incl. 5% safety margin) to 75% of peak demand.

Figure 62: Proposed interconnection process. Changes to the old interconnection process are highlighted in green.

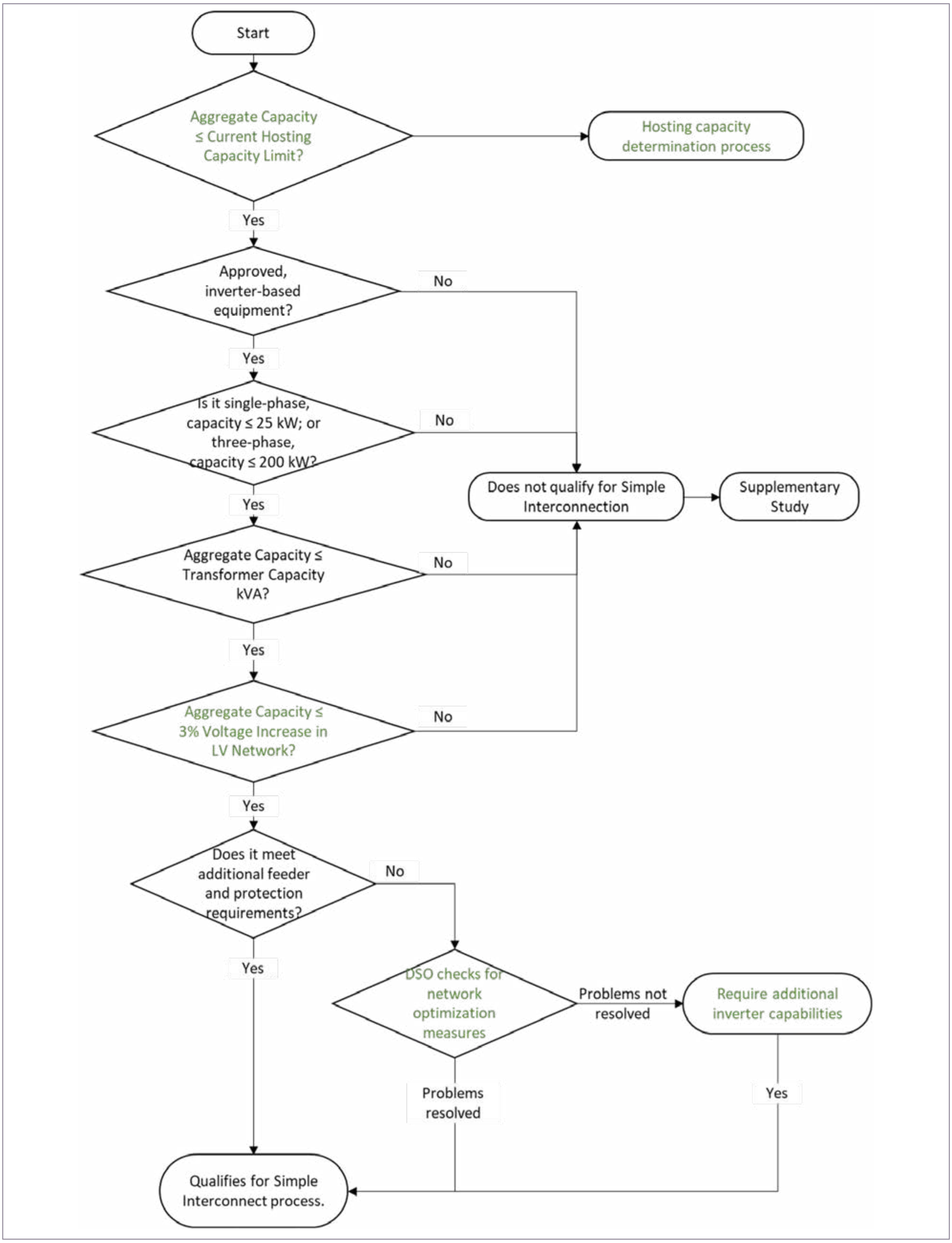


Figure 63: Proposed process for determining the current hosting capacity limit for a distribution feeder

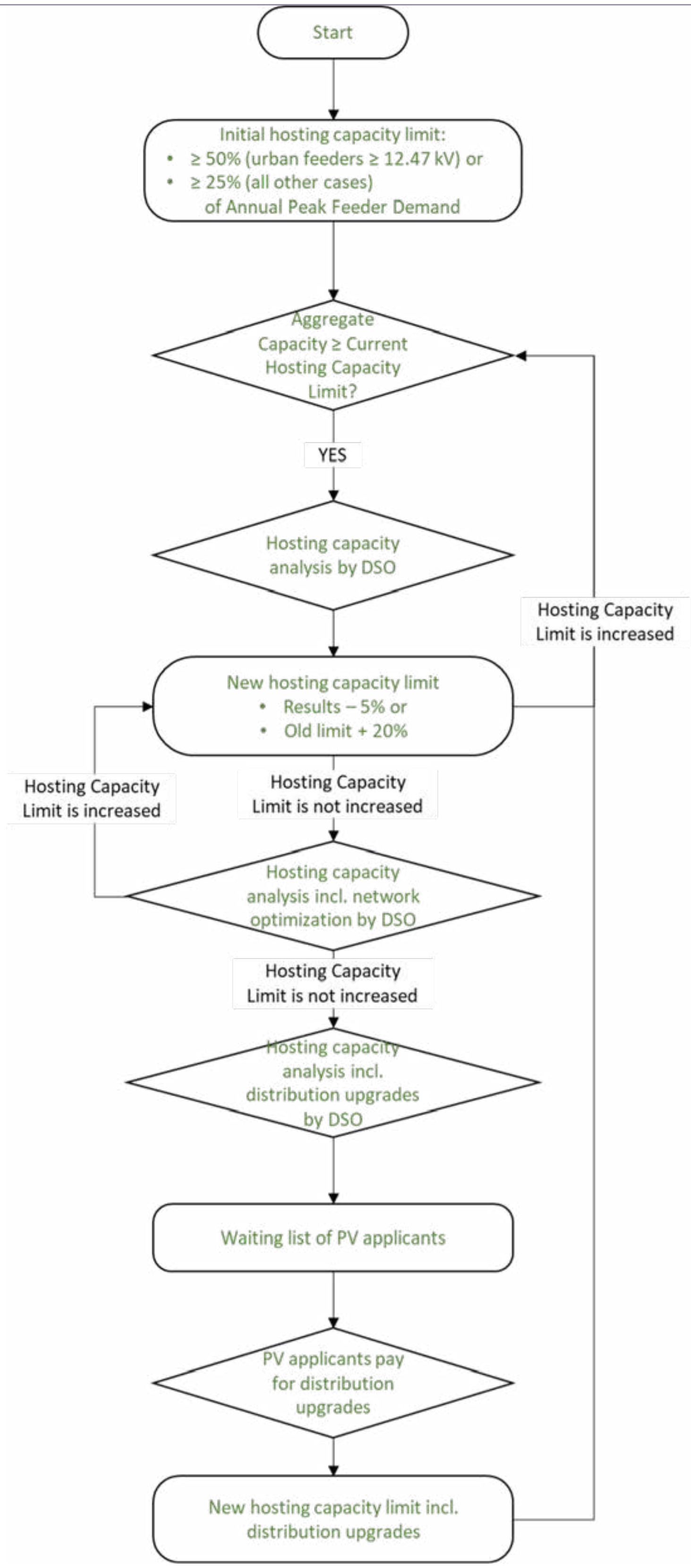
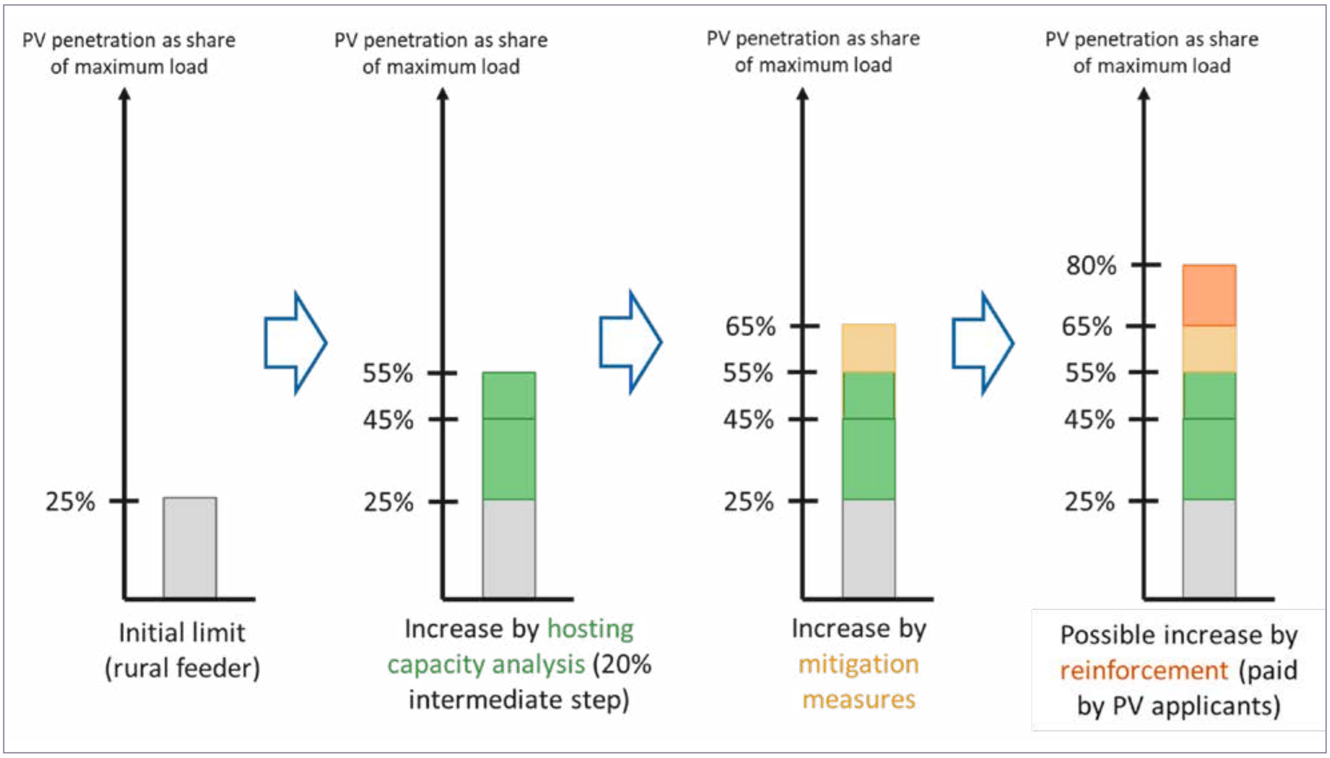


Figura 64: Illustration of accommodation capacity measures, including mitigation measures and network reinforcement



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