Voltage Regulation and Reactive Power Services from Rooftop Photovoltaic Systems for Distributed Generation Rates

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Abstract

The electrical power grid is a fundamental component of the socio-economic development of a country. Nowadays, the electric sector faces key challenges with an increased use of renewable energy sources. Distributed generation (DG), generation close to the point of use, has gained important participations in distribution networks around the world. There are many studies regarding the integration of distributed renewable energy sources. In many states of the U.S. and Puerto Rico a significant number of customers have solar photovoltaic systems. DG defies the traditional rate structures, thus there are rate programs for DG customers like net metering, or feed-in tariffs. However, these cannot be maintained in cases where penetration is high because these rates do not account for the effect DG has on the grid. This thesis focused on the study of the active and reactive power supply, and the costs of these services. The analysis was made for the case in Puerto Rico, with focus on residential customers. The work will contribute to the analysis and discussion of alternatives for an increased use of renewable energy in the Island and fair rates associated to renewable sources.

Resumen

La red eléctrica es una parte fundamental del desarrollo socioeconómico de un país. Hoy en día, el sector eléctrico enfrenta desafíos importantes debido a mayor uso de fuentes de energía renovables. La generación distribuida (GD), generación cercana al punto de consumo, ha ganado participaciones importantes en redes de distribución en todo el mundo. Existen muchos estudios sobre la integración de fuentes de energía renovable distribuida. En muchos estados de los Estados Unidos y Puerto Rico un número significativo de clientes tienen sistemas solares fotovoltaicos. La GD desafía las estructuras tarifarias tradicionales, por lo que existen programas de tarifas para los clientes de la GD, como la medición neta o las tarifas "Feed-in". Sin embargo, en los casos en que la penetración es alta, éstas no pueden mantenerse porque estas tasas no tienen en cuenta el efecto que la GD tiene en la red. Esta tesis se centró en el estudio de suplir potencia activa y reactiva, y los costos de estos servicios. El análisis se hizo para el caso en Puerto Rico, con énfasis en clientes residenciales. El trabajo contribuirá al análisis y discusión de alternativas para un mayor uso de energía renovable en la Isla y tarifas justas asociadas a fuentes renovables.

To my family…

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List of Abbreviations

DG	Distributed Generator, Distributed Generation
DER	Distributed Energy Resource
IEEE	Institute of Electrical and Electronics Engineers
PV	Photovoltaic
PV DG	Photovoltaic Distributed Generation
RPS	Renewable Portfolio Standard
PREPA	Puerto Rico Electric Power Authority
NEM	Net Energy Metering
VOS	Value of Solar
FVT	Full Value Tariff
OPF	Optimal Power Flow
IPM	Interior Point Method

1. INTRODUCTION

Justification

There is an urgent need to move from the current status of electrical energy systems to a new energy portfolio in Puerto Rico. The Island has excellent renewable energy resources that are underutilized. Act 57-2014 [1], gives a new mission to the Puerto Rico Electric Power Authority (PREPA): to provide electric energy for a sustainable future that maximizes the benefits and minimize the social, environmental and economic impacts; to promote renewable energy, the conservation, energy efficiency, transparency and citizen participation. Furthermore, a huge bond debt has resulted in the worst financial crisis in PREPA's history, caused in part by the absence of periodic rate revisions (the last one in 1989). Options to the crisis, the lack of tariff revisions and the fulfillment of the Act 57 are presented as separated elements, even though these challenges need to be addressed holistically, to avoid closing future opportunities. Distributed generation (DG) systems benefit customers and promote local economic development. Hawaii is an example that a positive change is possible through DG. Hawaii leads the nation with 12% of integration of residential rooftop photovoltaic systems. Puerto Rico and Hawaii are electric systems that have similar challenges high electricity costs and oil dependency. Solar rooftop is growing in many states, thanks to net metering. But net metering is not a sustainable rate [2], because solar customers use the grid but pay less to maintain it due to the way electric rates are traditionally determined. There is no independent study documenting what are the distributed solar costs for utilities, and what benefits it offers to the grid [2]. The Puerto Rico Energy Commission (PREC) is in charge to inspect the PREPA's rate revision procedure. In January, 2017 they approved the rate revision petition from PREPA with a reduction of 21% of the provisional rate [3].

Furthermore, Act. 133-2016 ordered the Puerto Rico Energy Policy Office (OEEPE) to define and provide the framework for solar communities and microgrids in Puerto Rico, which will be regulated by the PREC. The time for deep changes has arrived, and we have to work together to change the current status of the electric sector in Puerto Rico. This work will contribute to the analysis and discussion of alternatives for an increased use of renewable energy in the Island by providing alternative rates for DG customers, accounting for the benefits and constraints to the grid.

Objectives

The main objective of this thesis is to analyze the costs associated with the distribution network in order to allocate a fair charge to DG customers, with a particular focus on rooftop photovoltaic systems. Also, to analyze the benefits provided by DG customers to grid in order to propose fair compensation to those customers, with particular focus on rooftop photovoltaic systems. This thesis includes the following specific objectives:

- Estimate the costs of distribution that can be associated to DG customers.
- Identify the benefits DG brings to the grid, including power quality benefits.
- Complete a cost-based analysis of distributed generation in distribution systems.
- Focus rate alternatives study on demand levels and energy purchase contracts.

Structure of the Thesis

A basic introduction into the concept of Distributed Generation, including the impacts of DG in distribution systems is presented in Chapter 2. A discussion of PV technologies is presented in

Chapter 3. Chapter 4 describes the simulation software and circuit models used to evaluate the interactions between the DG and the distribution feeder, with emphasis ancillary services. Results from several simulations scenarios are discussed as well as the results from the cost analysis. Chapter 5 presents the conclusion, recommendations and future work.

2. DISTRIBUTED GENERATION

A fundamental part of the development of a country is the electrical power infrastructure. Traditionally, generators were connected in the transmission networks [4]. Today's modern power systems are complex, with centralized generation plants, and a transmission and distribution system that deliver the power to the customers. Because of long and overloaded lines, the power system can have low voltages problems at the end of lines. Distributed generation (DG) is the operation of smaller generators in parallel with the power system, usually connected at the distribution level [5]. DG has gained important participations in distribution networks around the world. This change is important because DG can contribute to limit the dependence on fossil fuels and decrease environmental pollution [6]–[8].

Most popular DG technologies include photovoltaics, wind turbine and fuel cells, among others. DGs are interconnected at the substation, distribution feeder or customer load levels [9]. Typically, DGs range in size from 3 kilowatts (kW) to 10 megawatts (10 MW) but could be larger. The smaller systems are used by residential customers, while larger systems are used by commercial and industrial customers [10].

The integration of distributed PV in distribution feeders can provide benefits to utilities and customers. DG can help to improve the voltage profile along the feeder, can supply reactive power if the network needed and can help to follow the load to make less fossil fuel energy generation, which is the case of Puerto Rico. It is important to understand what configurations of DG will maximize the benefits to the distribution system while avoiding the problems that can arise under certain circumstances. Current public policy in Puerto Rico calls for aggressive integration of renewable energy systems to the grid, particularly of distributed systems.

The introduction of distributed generation sources in a distribution system can impact to the flow of power and voltage condition at customers and utility equipment. These impacts can be positive or negative, depending on the distribution system operating characteristics and the DG characteristics. Some positive impacts of DG are voltage support and improved power quality, loss reduction, transmission and distribution capacity release, deferments of new or upgraded transmission and distribution infrastructure and improved utility reliability [11]. Negative impacts of DG in distribution systems could be: reverse power flow, voltage rise that cause over voltages, voltage fluctuations, among others [12].

Many new distributed generation systems are being installed, and it is important to know and deal with the power system impacts of these DGs to avoid degradation of power quality, reliability and control of the utility system [13], [13]. Power quality is an important topic in electrical industry. The term of power quality is more general than voltage issues because the continuity of supplying power includes both voltage and current quality [14]. There is extensive research on the technical advantages of connecting DGs to the distribution networks and how to deal with its impacts, including power quality [8]. The IEEE Interconnection Standard, IEEE 1547, is the standard developed to provide uniformity in guidelines for distributed resources interconnection [13].

To gain a better understanding of how rooftop PV will interact with distribution networks, and what are the associated benefits, simulations from a validated model of a 13.2 kV feeder were carried out. Different scenarios were developed and simulated to see how the benefits change along a distribution feeder. The goal is establishing which combination would provide most benefits at the lowest costs. The main problems studied were voltage compliance with upper/lower limits, reactive power supply and load following.

2.1. Electric Energy in Puerto Rico

Puerto Rico depends 99% in fossil fuel for electric power generation: 45% oil, 37% natural gas and 17% coal (as of fiscal year, 2014). The remaining 1% comes from renewable sources like hydroelectric, wind, and solar photovoltaic. The Puerto Rico Electric Power Authority (PREPA) is the only electric utility in the island. Most of the overall costs of electricity in Puerto Rico comes from fuel costs, being oil the largest contributor due to its high cost and price volatility [15]. There is a direct link between the cost of electric energy and any variation in the price of the barrel of oil. Average cost per kWh sold in Puerto Rico during 2012 was $0.2778.

The best renewable energy resource in Puerto Rico is solar energy. Various organizations and entities have kept insisting on the need to change Puerto Rico’s energy sources, technologies and practices. UPRM researchers have delivered seminal work on renewable energy sources and technologies, for example the first distributed generation (DG) studies in Puerto Rico.

2.2. Net Metering

The design of a tariff that ensures fair compensation for clean, distributed energy resources is a challenge. Examples of rates that have tried to deal with this challenge are net energy metering (NEM) and feed-in tariffs (FIT) [16]. Net metering is a billing system that allows electric customers to sell to their electric company any excess electricity generated by their DG systems. The customer is credited for the amount of kilowatt-hour (kWh) sold back to the grid and is charged for periods when their consumption exceeds their generation. The customer is both charged and credited at the utility’s full retail rate of electricity [10]. A net energy meter measures these exchanges. It is a solid state, multi-measurement, highly accurate electronic meter capable of measuring the flow of energy in both direction, from the utility to customer and from the customer to the grid. NEM policies vary from state to state [16]. The Net Energy Metering program can yield an under-recovery of distribution and transmission capacity costs by utilities and this is one of the main reasons that utilities are looking for new rate programs [17].

2.2.1. Hawaii

Hawaii is one of the states that are leading in the use of distributed generation. Hawaii's electric utilities lead the nation in the integration of residential rooftop solar photovoltaic (PV) systems. Hawaii has 17% of rooftop systems, and over 77,000 solar photovoltaic (PV) systems approved or interconnected [18]. They are at the forefront of the interconnection challenges associated with high distribution circuit penetration levels and will lead the way in solving these challenges. The Hawaii Public Utilities Commission on April 28, 2014, ordered a Distributed Generation Interconnection Plan (DGIP) [19]. The vision for the future is to deliver cost-effective, clean, reliable and innovative energy services to the customers, creating meaningful benefits for Hawaii's economy and environment, and making Hawaii a leader in the nation's energy transformation [19]. The future goals are a reduction in full service residential customer bills of more than 20% by 2030; 100% of the electric energy provided by renewable energy resources by 2045; distributed energy resources, such as rooftop solar and demand response, playing a greater role in their energy portfolio; lower cost, cleaner fuels replacing the remaining use of expensive imported oil [19].

NEM was a way used in Hawaii to connect renewable energy system of 10 kilowatts (kW) and smaller for distribution connections and up to 100 kilowatts (kW) for customer rooftop [20].

The excess of energy produced by the PV system and not used immediately, is sent to the electric grid and credited to the user account. Using the NEM system, instead of being credited at the retail electricity rate of \$0.295 per kilowatt-hour (kWh), Oahu solar owners had a tariff rate of \$0.147 per kWh; on Maui, the tariff varied from \$0.351 per kWh to \$0.223 per kWh and on Hawaii, it was from \$0.359 to \$0.186 per kWh [21]. Some of NEM charges that were used in the NEM bill are shown in table 1 [22].

The Hawaii Public Utilities Commission eliminated the Net Metering Program for new participants due to the high penetration of renewable energy and the need to move to a redesigned market-based structure for DG for the 100% renewable portfolio standard sought for 2045 [23]. New tariffs programs were developed for DG customers: "self-supply" and "grid-supply". The self-supply option is for PV customers with energy storage, and are restricted in the amount of electricity they can send back to the grid, but do not receive any compensation for the exports [23].

The grid-supply option, the PV customers can export the electricity to the grid, but will be compensated for the exports at a lower rate, a reduced one from the full retail rate from net metering, which was from 15 cents per kWh to 28 cents per kWh [23].

Table 1: Example of Hawaii's NEM Bill charges [22]

Bill Detail	
Current Charges	
Electric Service R Residential Signed NEM Contract	
Customer Charge	\$9.00
Base Fuel Energy	\$12.65
Non Fuel Energy	\$7.54
Energy Cost Adjustment	\$6.53
IRP Cost Recovery	\$0.08
PBF Surcharge	\$0.63
Purchased Power Adjustment	\$2.98
RBA Rate Adjustment	\$0.36

NEM Credit	$30.77-
Total for Current Charges	$9.00
Total Amount Due	$9.00

2.2.2. California

California has a commitment to have a clean and sustainable energy future [24]. One of the ways to achieve this goal is distributed renewable generation, especially the solar energy. California has the California Solar Initiative (CSI) Program, a DG solar incentive program, which is the base of the growth of the solar market. California had 7.8 million of single-family homes, of which only 2% have solar PV, by 2013 [24]. Net energy metering is a special billing that provides credit to customers with solar PV systems for full retail value of the electricity their system generates. Over 12-month period, the customer pay only for the net amount of electricity used from the utility over-and-above the amount of electricity generated by their system, in addition to monthly customer transmission, distribution and meter services charges. For PG&E solar and renewable customers, of 1MW or less, are eligible for NEM. On July, 2016 the California Public Utilities Commission (CPUC) announced that the CSI Program reached its goal for customer-installed solar energy before the scheduled date [25].

2.2.3. Texas

The Public Utility Commission of Texas (PUCT) has authorized the inclusion of distributed generation into Texas electric system. The benefits of using distributed resources to the state are: more competitive options, potentially reducing customer energy, improving the asset utilization of TDU distribution systems, firming up reliability and improving customer's power quality [26].

2.2.3.1. Value of Solar Residential Rate

The Value of Solar (VOS) Residential Rate is a rate tariff that would move beyond NEM and more accurately measure the tangible and intangible benefits that solar energy add to its municipal electric grid [27]. It was designed by Austin Energy in collaboration with Clean Power Research and approved by the Austin City Council in June 2012 [27]. It replaces net metering for residential solar photovoltaic systems not greater than 20 kilowatts (kW) [27]. This program is like feed-in tariff, but has some important distinctions, mainly that the tariff rate is not set for a contract term, and may be adjusted annually according to Austin Energy's calculated value of solar, which incorporates solar energy and generation in addition to other value components such as its environmental and transmission and distribution mitigation value. The initial rate was set at $0.128/ kWh [27]. On 2016, the solar rate was 10.6 cents per kWh [28].

2.2.4. Arizona

The Arizona Public Services (APS) conducted a multi-session technical conference on January, 2013 to evaluate the costs and benefits of renewable DG and net energy metering. Using new solar DG systems will provide benefits for the APS service territory for the next 20 to 30 years [29]. They had renewable generation of 4% in 2013. The plan is to increase this to 10% in 2020 and 15% by 2027 [29]. Solar rooftop owners participating in APS's NEM program receive credits on their next utility bill for excess electricity exported onto the grid at retail rates, which currently range is between $0.13 per kWh to $0.16 per kWh. On November, 2013, the Arizona Corporation Commission voted to implement a $0.70/kW fee for the rooftop solar customers under NEM program. The APS proposed two reforms to its net-metering rate structure: "Net-metering Option" and "Bill credit option" [30]. After some debates, at the end of 2016, the Arizona Corporation Commission approved to replace the Net Metering Program with a program based on a five-year average of utility-scale solar PPA pricing [31]. They used a methodology called "Resource Comparison Proxy" (RCP) which calculates the distributed energy export rate in all utility rate cases. In the future, the export rates will be determined by the RCP or by the avoided-cost methodology that uses five-year forecasting to evaluate the costs and values of energy, capacity and other services from DG to the grid [31].

2.2.4.1. Net-Metering Option

Under this option, the APS would place residential customer on a regular rate plan and give them a credit toward their bill for power produced by their solar energy system at an avoided cost rate based on the forward market at Palo Verde Nuclear Generation Station. This option turns the residential net-metered customers in wholesale producers, and must sell their excess power to APS at $0.04 kWh [30].

2.2.4.2. Bill Credit Option

Under this option, the APS would place residential customer on a regular rate plan and give them a credit toward their bill for power produced by their solar energy system at an avoided cost rate based on the forward market at Palo Verde Nuclear Generation Station. This option turns the residential net-metered customers in wholesale producers, and must sell their excess power to APS at $0.04 kWh [30].

Table 2: Benefits and Costs of Solar DG on the APS System [29]

Benefits	20-year levelized cents per kWh (2014 $)
Energy	6.4 to 7.5
Generation capacity	6.7 to 7.6
Ancillary services & Capacity reserves	1.5
Transmission	2.1 to 2.3
Distribution	0.2
Environmental	0.1

Avoided Renewables	4.5
Total Benefits	**21.5 to 23.7**
Costs	**20-year levelized cents per kWh (2014 $)**
Lost retail rate revenues	13.7
DG incentives	0 to 1.6
Integration costs	0.2
Total Costs	**13.9 to 15.5**

2.3. New York Case

New York is one of the most active state on new policies for renewable distributed generation. The New York's Reforming the Energy Vision program has the main goal to deliver cleaner and more distribution generation at lower prices. They are moving from NEM program to other alternatives more effective. The fundamental problem and one of the biggest challenges is to move from cost-of-service to market-based and maintaining the financial integrity of electric utilities [32]. The ratemaking challenge is to create alternatives to the current financial and institutional incentives and, provide opportunities for utilities to earn from activities that achieve their service obligations but not affect the reductions in the total customer bill. The changes to rate tariff must not cause large sudden increases in customer bills. Also, the customer investments under NEM program should not be disrupted [33]. They are proposing new methods for calculating value of distributed renewable energy using the marginal pricing. If the marginal costs are applied correctly can lead to fair and effective rate design and can give accurate price signals for consumers [34].

Two examples of proposed rates are: Economic Rate and Full Value Tariff (FVT). The Economic Rate program tries to combine the marginal cost based prices of distribution value with the other marginal costs of the electric system. It will have three parts and are detailed on table 3 [35]:

- Customer charge ($/customer): embedded costs associated with serving the customer (meter, meter servicing customer billing, etc.)
- Demand charge ($/kW of coincident and non-coincident peak loads): embedded costs based on a customer use of the grid and regulatory balancing accounts, among others.
- Marginal costs ($/kWh): forward looking marginal or avoidable costs of serving customer load, including energy costs and losses, avoidable deliver capacity and generation capacity costs during peak demand periods and any avoidable merchant function charges.

Table 3: A Sample Rate [35]

Parts	Cost Component	Description	Estimated Range
Part 1: Customer Charge (Embedded Costs)	Customer Charge	Costs of meter, billing, etc.	$5-$20/ customer-mo
Part 2: Demand Charge (Embedded Costs)	Transmission/Sub-Transmission	Historical costs to be recovered	~$1-$5/kW
	Distribution	Historical costs to be recovered	~$1-$15/kW
	Other	Other historical, budget driven, or miscellaneous costs to be recovered	~0.5-4 cents/kWh
Part 3: Marginal Costs (Avoidable Costs)	Energy	Forecast LBMP values and includes monetized carbon, SO_2 and NOx costs plus generation marginal losses along with each utilities' merchant function charges	~5-7 cents/kWh
	Losses	T&D losses incurred	~0.5-1 cents/kWh
	Ancillaries	Forecast frequency regulation, reactive	~0.5-1.5 cents/kWh

		power, black start, and spinning/non-spinning reserves costs	
	Generation	Forecast ICAP values	~2-3 cents/kWh
	Transmission	Congestion element in the LBMP and ICAP values	N/A
	Sub-Transmission	Deferral/ avoided capacity cost value (Could be based on targeted 'hotspot' geographic value in locally constrained areas)	Locational ~0-4 cents/kWh
	Distribution	(could be based on targeted 'hotspot' geographic value)	
	Customer Charge	Forecast customer cost changes, i.e. for billing costs	~0-0.5 cents/kWh
	Public Purpose Charges	System Benefit Charges and Renewable Energy Portfolio Charges	~0.5 cents/ kWh
	Health, CO_2, Resiliency, etc.	Externalities to be potentially internalized	~0-5 cents/kWh

The other proposed rate is Full Value Tariff (FVT) and it is derived from the Fundamental Economic Rate. It maintains the principles and theoretical underpinnings of Fundamental Economic Rate, but simplify its structure implementation. The three components of the FVT are: customer charge, a sized-based network subscription charge and a varying kWh dynamic price [35]. The FVT focus on granular marginal cost based dynamic prices to signal the value of change in consumption of production. The network subscription charge is like the subscribed level of data in a cellular phone plan. The table 4 presents how the FVT could be.

Table 4: Analogue network subscription pricing by cell phone for electricity [35]

Sized Based Residential Charge (Monthly Consumption in Peak Month)	**300kWh?**	**400kWh?**	**500kWh?**	**700kWh?**	**1000kWh?**
Customer Charge	$ Customer Charge/ month + cents/kWh rate				
Network Subscription Service	$20/mo + Dynamic Price	$30/mo + Dynamic Price	$40/mo + Dynamic Price	$50/mo + Dynamic Price	$120/mo + Dynamic Price

The following table presents the difference between these two methods.

Table 5: The 'Three Part Rate' vs. Full Value Tariff Formulation [35]

	'Three Part' Rate based on Fundamental Cost-Causation Rate	**Equivalent Full Value Tariff Component**
1	**Customer Charge** ($/customer) collects embedded costs and expenses associated with serving the customer such as the meter, meter servicing customer billing	**Customer Charge** ($/customer) similarly based on the costs associated with serving the customer.
2	**Demand Charge** ($/kW of coincident and non-coincident peak loads) collects embedded cost and invariant costs of the grid based on a customer's use of the existing grid. Costs include distribution, sub-transmission, transmission, any remaining utility-owned generation assets of the grid, and regulatory balancing accounts, adders and true-ups.	**Network Subscription Charge** ($/max average kW-month for residential and small commercial, $/kW of subscribed demand for large commercial) collects the embedded costs and invariant costs of the grid based on the customer's use of the existing grid. Costs include distribution, sub-transmission, transmission, any remaining utility-owned generation assets of the grid, and regulatory balancing accounts, adders and true-ups.
3	**Marginal Costs** ($/kWh) collect forward looking marginal or avoidable costs of serving customer load, including avoidable zonal hourly energy costs and losses along with avoidable delivery capacity and generation capacity costs during peak periods and any avoidable merchant function charges allocated to peak hours.	**Dynamic Price** ($/kWh) collect forward looking marginal or avoidable costs of serving customer load, including avoidable zonal hourly energy costs and losses along with avoidable delivery capacity and generation capacity costs during peak periods and any avoidable merchant function, renewable energy, and efficiency programs. Also can include externalities linked to air emissions of CO_2, and criteria emissions (PM, SO_x, NO_x).

2.4. Ancillary Services

Ancillary services are an important part in a power system since they help to maintain a reliable and stable grid. Typically, ancillary services are provided by large conventional generators connected to the transmission network [36]. Nowadays these services can also be provided at the distribution level with the increase of DG in distribution systems. Some of the ancillary services are: reactive supply, peak load reduction, operating and spinning reserves, energy imbalance, network stability services [37]. The traditional rates, in vertically-structured utilities include these ancillary services without dividing them into the different types of services. Nowadays, it is important to separate these services and assign costs to each one to make fair tariff rates in an industry with less boundaries between transmission and distribution.

2.5. Changes in distribution network with distributed generation

The distribution network is facing many new challenges due to the increase of renewable distributed generation. As mentioned before, there are many states studying new ways to deal with these changes, including the distribution market and new policies to face the economic challenges. In the following sections, some of the challenges and improvements that can be made to the distribution network market are discussed.

2.5.1. Distribution Market

The increase of distributed energy resources (DERs), mainly due to falling costs and aggressive policies, has in turn increased the number of active customers. These customers, on one hand, may provide benefits for the power systems as they can potentially reduce system peak loads, shape the system load profile, and defer required generation and transmission upgrades.

On the other hand, a large penetration of these active customers could challenge the economic and reliable operation of the power system [38].

The transition from the conventional utility grid to the smart grid and the enhanced utilization of controllable loads may significantly change the way customers use electricity. Responsive consumers are defined as traditional end-use electricity customers that make use of new technologies in order to react to electricity price variations and/or respond to system operators signals for emergency conditions [38].

Prosumers are end-use electricity consumers which employ renewable DG to provide a local supply of electricity. Utilizing this local supply of electricity, prosumers can reduce their electricity payments by partially offsetting their electricity usage, avoiding T&D costs, and selling back excess generation to the grid [38].

The primary objective of proactive customers is to reduce their electricity payments to increase savings. In simple terms, when the electricity price in the utility grid is low the proactive customer would purchase power from the utility grid (it would act as a load), whereas when the electricity price is high the proactive customer would prefer to generate locally and potentially sell excess generation back to the utility grid to increase its economic benefits [38].

A variety of distribution operation and market models are already under study in the United States, such as the Distributed System Platform Provider (DSPP) introduced in New York via the Reforming the Energy Vision program, and in California the Distribution System Operator (DSO). There are additional proposed operating and market models including the Distribution Network Operator (DNO) and the Independent Distribution System Operator (IDSO) [38].

The DSO is defined as an intermediate platform between the proactive customers and the ISO that enables market activities for customers, coordinates with the electric utility to improve grid operations and interacts with the ISO to determine demand bids and awards. The ISO performs the market clearing process and determines the schedule of each directly connected player. The DSOs would have as major responsibilities: to receive demand bids from proactive customers, combine them and offer and aggregated bid to the ISO and to receive the day-ahead schedule from the ISO, solve a resource scheduling problem and subsequently determine proactive customers' shares from the awarded power [38].

2.5.2. Economic analysis for distribution network

There are different types of power system analyses typically, these are focused on generation and transmission rather than on the distribution network. With the increase in distributed generation, the analysis of distribution network is becoming more important. The next sections present an analysis focused on the distribution network.

2.5.3. OPF for distribution network

The Optimal Power Flow (OPF) problem is typically used to dispatch the generation of power while minimizing the generation cost in power network complying with operational and power flow constraints. It is also used for planning studies and operational control applications. Its main purpose is to optimize the static operating conditions of an electric power system. An OPF adjusts the controllable quantities in the system to optimize an objective function, while satisfying a set of physical and operational constraints [39]. It is an optimization mathematical problem. The traditional power system is a one-direction system, from generation to load. Due to nonconvex power flow constraints, the OPF problem is difficult to solve [40]–[43]. For transmission networks, the power flow constraints are approximated and the OPF is reduced to a linear problem, but this approach cannot be applied to distribution systems [40]. Nevertheless, OPF for distribution networks has become an important tool to analyze distribution networks with DG [40], [41]. For distribution networks, some algorithms to solve the OPF are: successive linear/quadratic programming, trust-region based methods, Lagrangian Newton method and interior-point methods [40], [43] .

2.5.3.1. OPF for microgrids

A distribution optimal power flow (D-OPF) solution is required for an economic and efficient operation of microgrid. A mixed integer quadratic constrained programming (MIQCP) based D-OPF model is proposed to optimize the operation of microgrid. This model minimizes the operating cost, including the fuel cost, purchasing cost and demand charge and the performance indices, including the voltage deviation, network power loss and power factor. It also co-optimizes the real and reactive power from DGs and batteries considering their capacity and power limits. The MIQCP model is reformulated as mixed-integer linear programing (MILP) by linearizing the nonlinear terms. The optimization objectives for a microgrid is to minimize the virtual cost associated with the system operating cost and performance which includes: fuel cost of DGs, cost/benefit of purchasing/selling energy from/to distribution grid, demand charge, voltage deviation, total network loss and reactive power exchange. These objectives are merged into one single objective function by their weighted summation. The weighting coefficients are calculated based on a matrix based on the comparisons of the relative importance of each factor with other factors [44].

The DG constraints for the objective function include the fuel cost of DGs by blocks, the DG output enforcement to zero, the power factor and capacity limit and the power generation inequality. The battery constraints are the maximum charging/discharging power, the state of charge limits, the power factor limits of a battery in charging/discharging states, the capacity limit and some logical constraints that will be simplified/linearized into mixed integer linear (MIL) format. The network constraints are: the linear form of DistFlow equations, the nodal voltage drop along a feeder, the real and reactive power balances across the networks, the nodal injection of real and reactive power, the maximum voltage deviation of all nodes and the line flow constraints. Finally, to reformulate the D-OPF problem into a MILP, the quadratic and logical terms need to be linearized [44].

2.5.3.1. OPF for wind turbines

A method for DNOs to evaluate the amount of wind power that can be injected into a grid and the effects of wind power penetration on locational marginal prices (LMPs) through the networks considering uncertainties is studied in [45[. The Monte Carlo simulation (MCS) method is used to model the uncertainties due to the stochastic nature of wind as well as the volatility of WTs' offers quantity and price. The market-based OPF uses constrained cost variable (CCV) approach to generate the appropriate helper variable, cost term and related constraints for any piecewise linear cost. Under the assumed DNO acquisition market, the market clearing quantity and price are determined by maximizing the social welfare (SW) while protecting network security. Its maximization implies both the minimization of the costs related to energy production and the maximization of the consumers benefit function. The optimization problem is formulated as follows [45]:

$$Maximize \quad SW = \sum_j B_j(d_j) - \sum_j C_i(g_i) \tag{1}$$

$$where \qquad B_j(d_j) = \frac{1}{2} m_d d_j^2 + b_j d_j \tag{2}$$

$$C_i(g_i) = \frac{1}{2} m_g g_i^2 + b_i g_i \tag{3}$$

The $C_i(g_i)$ and $B_j(d_j)$ are the production cost and benefit of consumers, respectively

$$p_i = b_i + m_g g_i, \qquad for\ i = 1,2, \dots, I \tag{4}$$

Where

b_i is the intercept in €/MWh,

m_g is the slope ($m_g > 0$) in €/MW^{2}h

p_i is the price at which producer *i* is willing to supply in €/MWh,

g_i is the supply in MW

$$p_j = b_j + m_d d_j, \qquad for\ j = 1,2, \dots, J \tag{5}$$

Where

b_j is the intercept in €/MWh,

m_d is the slope ($m_d < 0$) in €/MW^{2}h

p_j is the price at which consumer *j* is willing to pay in €/MWh,

d_j is the demand in MW

The constraints are active and reactive power for the interconnection to the external network, (6) and (7); the voltage limits at all buses, (8); the flow constraints for lines and transformers, (9); the wind turbines active and reactive power constraints, (10); and dispatchable loads power constraints (11):

$$P_b^{min} \leq P_b \leq P_b^{max} \tag{6}$$

$$Q_b^{min} \leq Q_b \leq Q_b^{max} \tag{7}$$

$$v_i^{min} \leq v_i \leq v_i^{max} \tag{8}$$

$$S_k \leq S_k^{max} \tag{9}$$

$$0 \leq P_g \leq P_g^{max} \tag{10}$$

$$P_D^{min} \leq P_d \leq 0 \tag{11}$$

2.5.4. OPF for distribution network with reactive supply

The pricing of reactive power has received very little attention, and one reason is the economists' difficulty in understanding the concept [48]. The traditional optimal power flow models ignore the cost of reactive power [47]. The ancillary services are known by their minor costs, but are needed to hold the reliability of the system and meet an adequate security [47]. The average costs of reactive power technologies are: $5 to $20 per kVAR for capacitors; $10 to $30 per kVAR for reactors; $40 to $60 for Super-VAR and $75 to $100 per kVAR for Dynamic-VAR [49]. The marginal cost of reactive power can be positive or negative and are smaller than the active marginal prices [47], [48]. The active and reactive power marginal prices can be calculated with a modified OPF, using the interior point method [48].

The OPF can be used to obtain marginal costs per bus for active and reactive supply. These bus marginal costs provide price signals to load and generation for different locations and time. These signals can also be used for appropriate siting of DG in distribution networks or to determine the optimal time to inject active and/or reactive power. The presence of DG in the distribution network turns it into an active network. The DG should be rewarded because it reduces demand

and creates additional distribution capacity. Negative marginal prices resulting from OPF analysis mean that payments must be made to Distributed Energy Resources (DER) for the additional distribution network capacity provided [46], [47] . The “extra capacity” created by the DERs would be paid by the grid (i.e., other customers). This has the same effect as if the distribution company had added capacity itself and passed those charges to customers [46].

2.5.5. Interior-Point Method for OPF solutions

The interior-point method (IPM) is widely used due to its reduced computational time and high quality of the solutions. However this method only guarantee to find a local minimum [50]–[52]. The interior-point method has been used to solve the nonlinear OPF problem [50], [51], [53]. The interior-point method includes the Karush-Kuhn-Tucker (KKT) which guides to a local minimum due to the nonconvexity of the OPF problem [50]. The IPM also has been used to solve state estimation, loadability maximization, load shedding, voltage stability analysis, hydrothermal coordination and security constrained economic dispatch [51].

3. CIRCUIT MODEL AND MATHEMATICAL MODEL

3.1. Introduction

Current public policy in Puerto Rico calls for aggressive integration of renewable energy systems to the grid, particularly PV systems. It is important that to obtain the highest benefits from the integration of PV DG to the distribution grid while securing grid performance and power quality, it is necessary to understand how the abovementioned issues can manifest in distribution feeders typically found in Puerto Rico. The aim of this thesis is to determine how rooftop PV can provide some ancillary services and what is a possible method to assign costs to those services. To gain a better understanding of how rooftop PV will interact with distribution networks, simulations of a typical 13.2 kV feeder were carried out. Different scenarios were developed and simulated to see how changes in load capacity, load distribution, and DG capacity would interact with the distribution system. Particular attention was placed on load distribution, DG placement and penetration to establish which combinations would provide more benefits in ancillary services and to determine related costs.

3.2. Circuit Model

The simulation software used is DIgSILENT PowerFactory, a leading power system analysis software for modelling and studying generation, transmission, distribution and industrial grid and analyzing grid interactions. This software has set standards and trends in power system modelling, analysis and simulation for more than 25 years. It is the most economical solution, as data handling, modelling capabilities and overall functionality replace a set of other software systems, thereby minimizing project execution costs and training requirements. The software includes models for equipment such as conductors, transformer, voltage regulators, capacitors, motors and loads. The user can work with available models, can modify existing ones or can prepare new models using equipment data provided by the manufacturer.

The software focuses on steady state evaluations of the circuit and does not perform time varying analysis. This means that the interaction between DGs, loads and voltage regulating equipment as load and DG output vary cannot be modeled against time. Taking this into consideration, the simulations performed focused on steady state voltages along the feeder with varying DG penetration under conditions of different demand levels during the day.

The first step when performing the simulations is to develop the circuit model. For this, a 13.2 kV feeder model with typical line parameters to provide the flexibility to incorporate different load and DG combinations was developed. A length of 10 kilometers (6.21 miles) was chosen. The model was developed for a previous study of the impact of DG penetration at 4.16kV and 13.2 kV [54]. The model used software not available at UPRM, thus the model was recreated using DIgSILENT, and validated using the previous work. This model was chosen because it represents a general feeder that allows the evaluation of different load combinations and include some typical conductor sizes in Puerto Rico. This feeder is representative of 35% of the feeders in the Island and is considered by PREPA as a medium feeder because of its length.

The circuit model consisted of a substation represented as an infinite bus, the grid, with a bus voltage specified at 1.05 p.u., the maximum voltage limit by ANSI Standard, which avoid the fast drop in voltage across the feeder. The feeder consisted of a long mainline and three lateral branches. The feeder was divided into four sections of equal length. Each section was made up of ten segments, each measuring 250 meters (820 feet), for a total length of 2.5 km per section, and

10 km in total. Figure 1 shows an online diagram with the sections and the seven evenly distributed installed DGs.

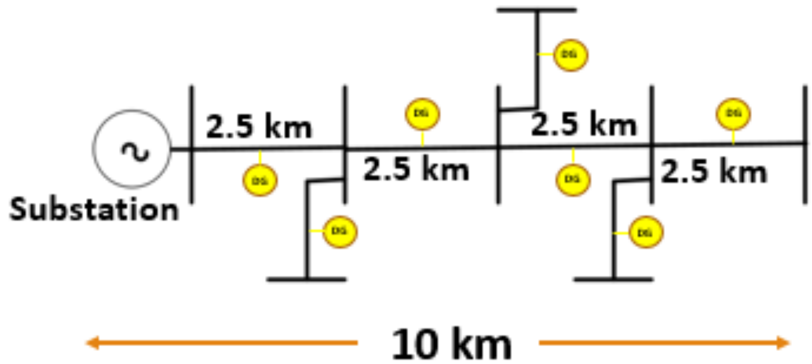

Figure 1: Online circuit diagram

The segments were assigned one of three different conductor types, based on their position in the circuits. The first 13 segments of the feeder have 556 ACSR conductor. The next third of the feeder was constructed using 266 ACSR. The rest of the feeder used 1/0 ACSR, with the final segment built with 4 CU HD. The generic feeder included three sections representing three phase lateral branches. The laterals were connected at 2.5 km intervals along the mainline. They were each divided into twelve segments measuring 100 meters, for a total length of 1.2 km (0.5 mi) per lateral. The first six segments, or 600 m, of each lateral branch, were constructed using 1/0 ACSR, while the remaining six used 4 CU HD. The conductors chosen represent conductors commonly found in feeders around the island. Table 6 lists the conductors used and some of their electrical properties. Figure 2 illustrates the layout of the circuit.

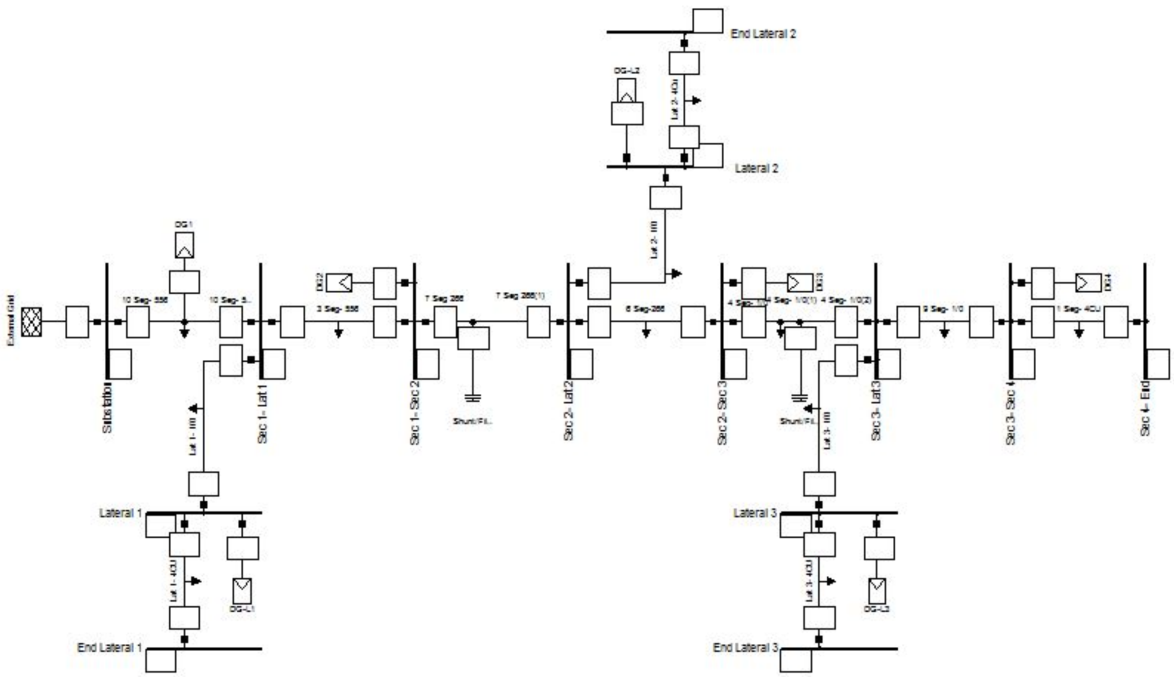

Figure 2: Circuit Model of DIgSILENT

The load was evenly distributed along the feeder for each period, with the peak load periods between 4pm to 10pm. Figure 3 shows the distribution of load assumed for each period. This load profile corresponds to Puerto Rico's residential demand profile on September 2013. For the analysis of DG injection to the grid, two cases were studied: sunny and cloudy day. For each case an output curve was estimated from the solar curve irradiance assuming the peak sun period. From 11am to 4pm, the seven evenly distributed DGs can produce all of their installed capacity, 11 MVA. For the sunny day, data of a sunny day on June 2010 at Aguadilla, Puerto Rico was used from the National Solar Radiation Data Base of NREL website [55]. For the cloudy day, a graph simulated with MATLAB© for different cloudy days was used.

After the model was constructed, the DG were modeled as PV generators modifying the input of active and reactive power. Then, the software runs a power flow for the network and give the results of the voltage magnitude and angle of each bus of the system and the power flow. With this data, we can see how much penetration of DG allowed to the distribution network and which case will be better, evenly distributed or at end of the feeder for active and reactive power supply.

Table 6: Conductors data

Conductor Type	Material	Capacity (A)	Resistance (Ω/km)
556 ACSR	Stranded Aluminum	700	0.1026+0.3731j
266 ACSR	Stranded Aluminum	450	0.2141+0.4007j
1/0 ACSR	Stranded Aluminum	240	0.5343+0.8368j
4 CU HD	Solid Copper	180	0.8538+0.4901j

Figures 4 and 5 show the two output behavior for each period of the studied day for the sunny and cloudy day, respectively.

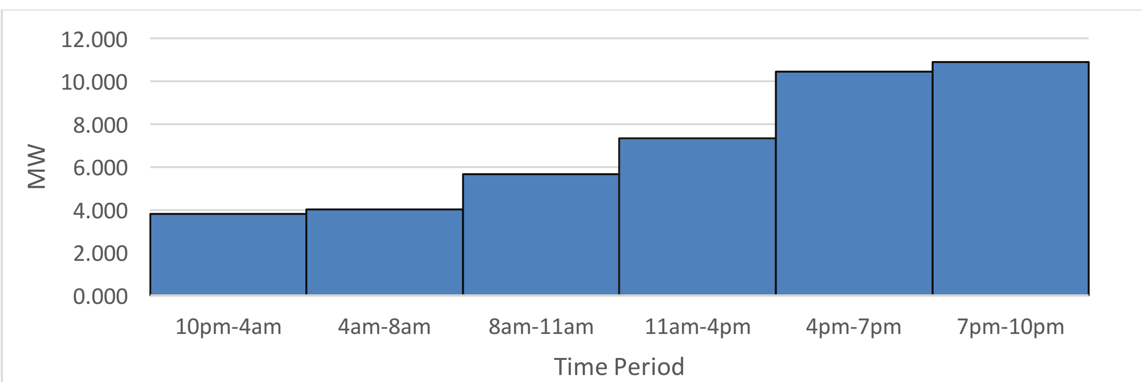

Figure 3: Load distribution for each period

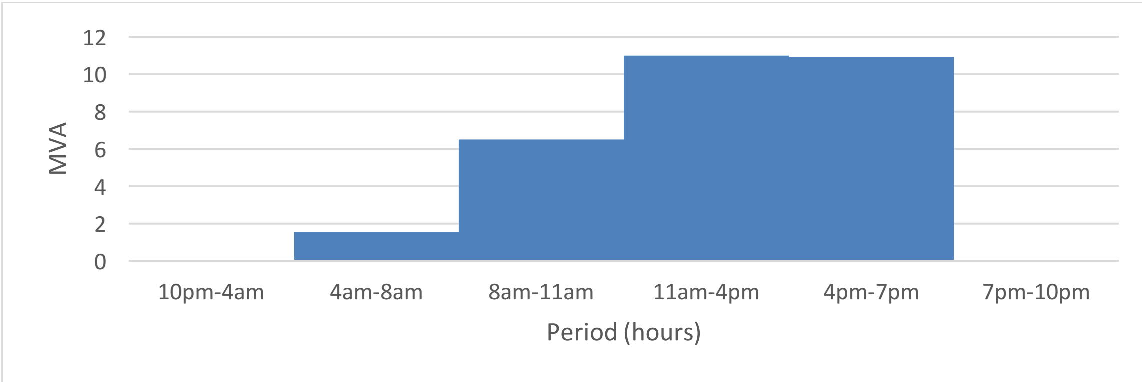

Figure 4: Sunny day DG output

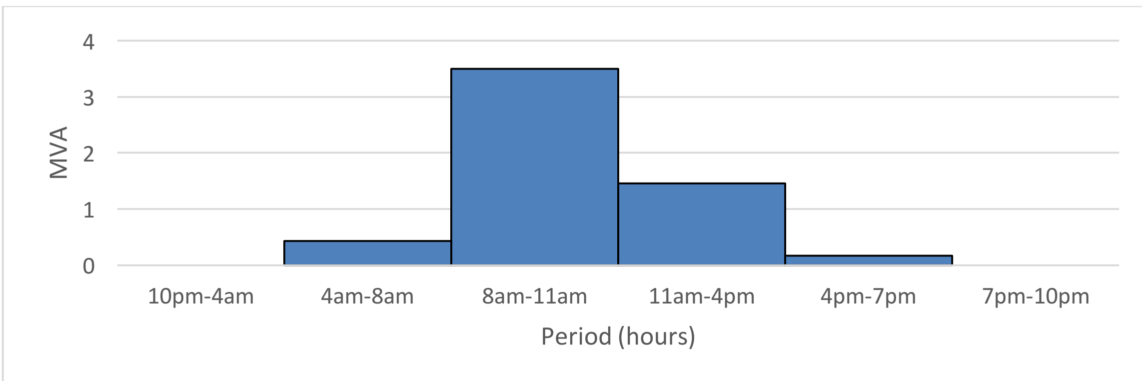

Figure 5: Cloudy day DG output

3.3. Active and Reactive Optimal Power Flow

The AC-OPF problem is typically performed to dispatch real power at least cost without any violation of constraints. The marginal cost is the sensitivity of generation production cost to the power demand and is used for the OPF formulation [56]. The AC-OPF used in this work also includes the reactive power generation, and it is specified as follows (see Table 7 for a description of variables used). The objective function (12) is the sum of polynomial cost functions f_P^i and f_Q^i of real and reactive power injections, for each generator:

$$\min_{\theta, V_m, P_g, Q_g} \sum_{i=1}^{n_g} f_P^i(p_g^i) + f_Q^i(q_g^i) \tag{12}$$

The equality constraints (13) and (14) are the real and reactive power balance equations:

$$P_{G_i} = P_{D_i} + \sum V_i\, V_m\, Y_{im} \cos{(\delta_i - \delta_m - \theta_{im})} \tag{13}$$

$$Q_{G_i} = Q_{D_i} + \sum V_i\, V_m\, Y_{im} \sin{(\delta_i - \delta_m - \theta_{im})} \tag{14}$$

The inequality constraints (15), (16) and (17) are the real and reactive power produced by the generators and voltage limits.

$$P_{G_i}^{min} \leq P_{G_i} \leq P_{G_i}^{max} \tag{15}$$

$$Q_{G_i}^{min} \leq Q_{G_i} \leq Q_{G_i}^{max} \tag{16}$$

$$V_i^{min} \leq V_i \leq V_i^{max} \tag{17}$$

Table 7: OPF variables definition

Variable	Definition
f_P^i	Cost Function for real power generator i
f_Q^i	Cost Function for reactive power generator i
P_{G_i}	Real power generation at bus i
Q_{G_i}	Reactive power generation at bus i
P_{D_i}	Real power demand at bus i
Q_{D_i}	Reactive power demand at bus i
V_i	Voltage magnitude at sending bus i
V_m	Voltage magnitude at receiving bus m
Y_{im}	Admittance magnitude between bus i and bus m

$\boldsymbol{\delta_i}$	Voltage angle at sending bus i
$\boldsymbol{\delta_m}$	Voltage angle at sending bus m
$\boldsymbol{\theta_{im}}$	Admittance angle between bus i and bus m
$\boldsymbol{P_{G_i}^{min}}$	Lower limit of real power generation i
$\boldsymbol{P_{G_i}^{max}}$	Upper limit of real power generation i
$\boldsymbol{Q_{G_i}^{min}}$	Lower limit of reactive power generation i
$\boldsymbol{Q_{G_i}^{max}}$	Upper limit of reactive power generation i
$\boldsymbol{V_i^{min}}$	Voltage lower limit
$\boldsymbol{V_i^{max}}$	Voltage upper limit
$\boldsymbol{C_{g_{pi}}}$	Quadratic generator cost function
a,b,c	Coefficients of quadratic equation
$\boldsymbol{S_{gi,max}}$	Maximum complex power capacity i
$\boldsymbol{Q_{gi,max}}$	Maximum reactive power generation i
$\boldsymbol{C_{fuel}}$	Fuel generator cost function
$\boldsymbol{C_{PV}}$	PV generation cost function

Reactive power supply is one of the most important ancillary services and it is becoming a necessity in electricity markets [56]. The variable costs of reactive power are often negligible and the charge for reactive power is determined by the availability of reactive power capacity [56]. The reactive power cost function (18) is obtained from the active power cost function. The cost function is modeled as:

$$C_{g_{pi}}(P_{gi}) = a + bP_{gi} + cP_{gi}^2 \tag{18}$$

The reactive power generation production cost is thus:

$$C_{g_{pi}}(Q_{gi}) = C_{g_{pi}}(S_{gi,max}) - C_{g_{pi}}(\sqrt{S_{gi,max}^2 - Q_{gi}^2}) \tag{19}$$

Assuming $S_{gi,max} = P_{gi,max}$, for the cases of reactive power generation, $S = Q$, the equation results as:

$$C_{g_{qi}}(Q_{gi}) = C_{g_{pi}}(S_{gi,max}) = C_{g_{pi}}(Q_{gi,max}) \tag{20}$$

MATPOWER 6.0, is a MATLAB open source tool for solving power flow and optimal power flow problems [57]. An OPF was carried out for different scenarios of PV-DG active and reactive power supply to determine the buses marginal cost. An M-file was created with the case information to perform the active and reactive OPF. This case file contained the buses information (bus number, bus type, active and reactive load, initial voltages, voltage base and voltage limits). The branches data needed were the sending and receiving end of the branches and the per unit impedance. And finally, to carry out the OPF, the generators cost functions are needed, including the number of the generator bus and the coefficients of the cost function.

The assumed generator cost functions (21) and (22) for fuel generator and PV DG are the following [58]:

$$C_{fuel} = 0.0250\, P_{fuel}^2 + 3 \tag{21}$$

$$C_{PV} = 3\, P_{PV} \tag{22}$$

Equation (22) was varied in a range from two to three to study the effect of various PV costs in the OPF results. For the case studied, the OPF is used to determine the cost of providing the active or reactive power for each generator. For this problem, an optimization problem that minimized the active and reactive generator cost function was used, without any violation of the equality and inequality constraints. The equality constraints are the power flow equations. The inequality constraints are the active and reactive power generation, the voltage limits and the angle reference limits. The MATPOWER OPF problem includes this formulation on its Standard AC OPF problem. The objective function has the active and reactive power generation cost function components and the constraints are the above mentioned.

The Standard OPF MAPTOWER includes code to solve both AC and DC versions of the OPF problem [59]. The standard version of each takes the following form.

$$\min_{x} f(x) \tag{23}$$

Subject to

$$g(x) = 0 \tag{24}$$

$$h(x) \leq 0 \tag{25}$$

$$x_{min} \leq x \leq x_{max} \tag{26}$$

The AC version of the standard OPF problem is a general non-linear constrained optimization problem, with both non-linear costs and constraints. In a system with n_b buses, n_g generators and n_l branches, the optimization variable x is defined in terms of the $n_b \times 1$ vectors of bus voltage angles θ and magnitude V and the $n_g \times 1$ vectors of generator real and reactive power injections P and Q as follows [59].

$$x = \begin{bmatrix} \theta \\ V \\ P \\ Q \end{bmatrix} \tag{27}$$

The objective function (23) is a simply a summation of individual polynomial cost functions f_P^i and f_Q^i of real and reactive power injections, respectively, for each generator.

$$\min_{\theta,V,P,Q} \sum_{i=1}^{n_g} f_P^i(p_i) + f_Q^i(q_i) \tag{28}$$

The equality constraints (24) consist of two sets of n_b non-linear nodal power flow balance equations, one for real power and one for reactive power.

$$g_P(\theta, V, P) = 0 \tag{29}$$

$$g_Q(\theta, V, Q) = 0 \tag{30}$$

The inequality constraints (25) consist of two sets of n_l branch flow limits as non-linear functions of the bus voltage angles and magnitudes, one for the *from* end and one for the *to* end of each branch [59].

$$h_f(\theta, V) \leq 0 \tag{31}$$

$$h_t(\theta, V) \leq 0 \tag{32}$$

The variable limits (26) include an equality limited reference bus angle and upper and lower limits on all bus voltage magnitudes and real and reactive generator injections [59].

$$\theta_{ref} \leq \theta_i \leq \theta_{ref}, \quad i = i_{ref} \tag{33}$$

$$v_i^{min} \leq v_i \leq v_i^{max}, \quad i = 1, \ldots, n_b \tag{34}$$

$$p_i^{min} \leq p_i \leq p_i^{max}, \quad i = 1, \ldots, n_g \tag{35}$$

$$q_i^{min} \leq q_i \leq q_i^{max}, \quad i = 1, \ldots, n_g \tag{36}$$

The i_{ref} denotes the index of the reference bus and θ_{ref} is the reference angle.

Table 8 summarizes the experimental conditions for different cases:

Table 8: Experimental Conditions Summary

Variables	Case 1	Case 2	Case 3	Case 4	Case 5
Substation Voltage	13.85 kV (1.05 p.u.)	13.85 kV (1.05 p.u.)	13.2 kV (1.00 p.u.)	12.54 kV (0.95 p.u.)	13.85 kV (1.05 p.u.)
Kind of day	Sunny	Sunny	Sunny	Sunny	Cloudy
Maximum generation output	11 MVA	11 MVA	11 MVA	11 MVA	3.5 MVA

4. RESULTS AND ANALYSIS

4.1. Voltage Regulation

A voltage regulation study was performed for a sunny and cloudy day, with six (6) different periods of 24-hours, for DG evenly distributed and located at the end of the feeder. The DG can produce power depending on factors such as the solar curve. These simulations where performed assuming the DG produces its maximum capacity during the period from 11am to 4pm. The next sections present the most representative cases. Further supporting results are presented in the Appendices.

4.1.1. Case 1- Sunny Day Voltage Regulation

During a sunny day, the DG can produce its maximum output possible. The simulations show that with evenly distributed DG, more penetration of power can be integrated to the grid than with DG at end of feeder. Figure 6 shows evenly distributed DG can penetrate as much as 3.25 MW without violating the voltage limits of ANSI C84 mentioned before. At the end of the feeder, during this period, there is a voltage improvement of 1.62% when DG delivers 3.25 MW (50% of what can generate). Table 9 shows the voltage improvement percentages for 8am to 11am period when DGs are evenly distributed. Figure 7 presents the results when the DG can produce its maximum capacity (11 MW), only 5.5 MW (50%) can be used when DGs are evenly distributed due to voltage limitations (ANSI standard). This penetration causes an improvement of 3.22% at end of the feeder, as shown in Table 10. This reduces the possibility of customers experiencing problems due to low voltages related to natural events or accidents.

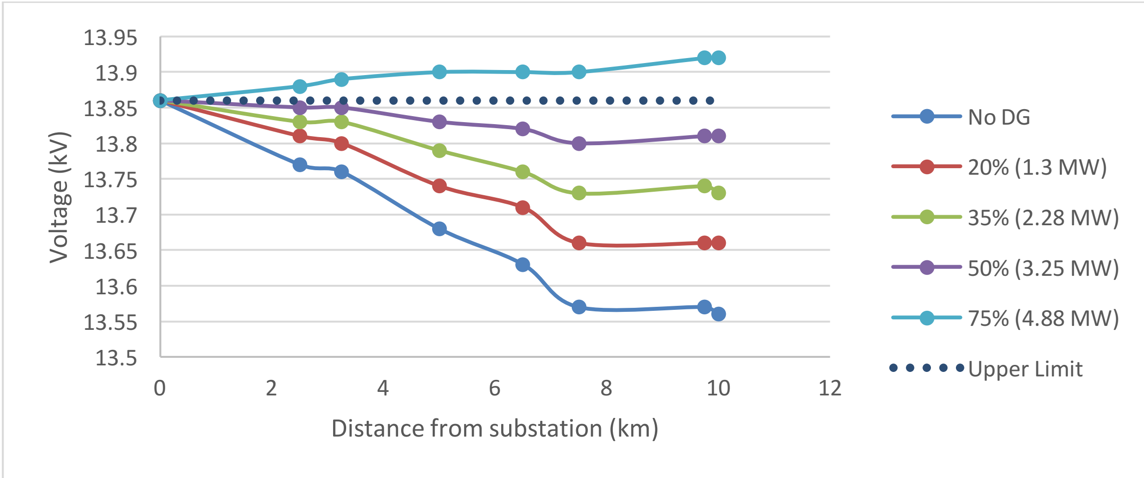

Figure 6: Voltage along the feeder with DG evenly distributed for 8am-11am

Table 9: Voltage improvement for the 8am-11am period, sunny day (evenly distributed DG)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.29 %	0.44 %	0.58 %	*	*
3.5	0.29 %	0.51 %	0.65 %	*	*
5	0.44 %	0.80 %	1.10 %	*	*
6.5	0.59 %	0.95 %	1.39 %	*	*
7.5	0.66 %	1.18 %	1.69 %	*	*
9.75	0.66 %	1.25 %	1.77 %	*	*
10	0.66 %	1.33 %	1.84 %	*	*

Table 10: Voltage improvement for the 11am-4pm period, sunny day (evenly distributed DG)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.44 %	0.73 %	1.02 %	*	*
3.5	0.51 %	0.88 %	1.24 %	*	*
5	0.89 %	1.48 %	1.99 %	*	*
6.5	1.04 %	1.78 %	2.45 %	*	*
7.5	1.27 %	2.17 %	2.91 %	*	*
9.75	1.35 %	2.24 %	3.14 %	*	*
10	1.42 %	2.32 %	3.22 %	*	*

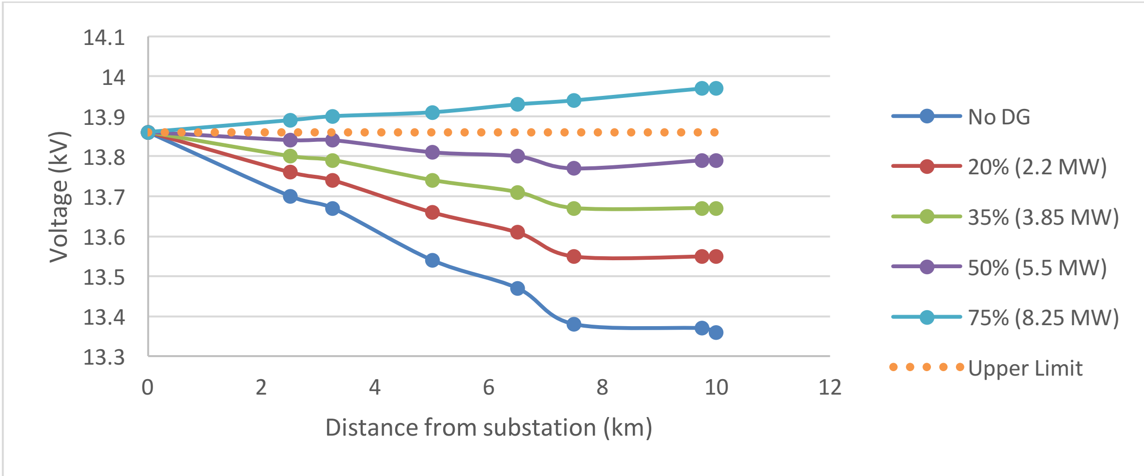

Figure 7: Voltage along the feeder with DG evenly distributed for 11am-4pm

The peak load period shown in Figure 8, DGs can supply 6.44 MW if they are evenly distributed; but only 3.22 MW (50% of what can produce on this period) when DG is at end of the feeder, as shown in Figure 9. During this period, the voltage decreases significantly without DG. The voltage at end of the feeder with maximum DG penetration increases 4.23%. Table 11 presents the percentages of voltage improvement when DGs are evenly distributed. Appendix A.1 and B.1 present the voltage plots and improvement percentages for the case of voltage regulation on a sunny day.

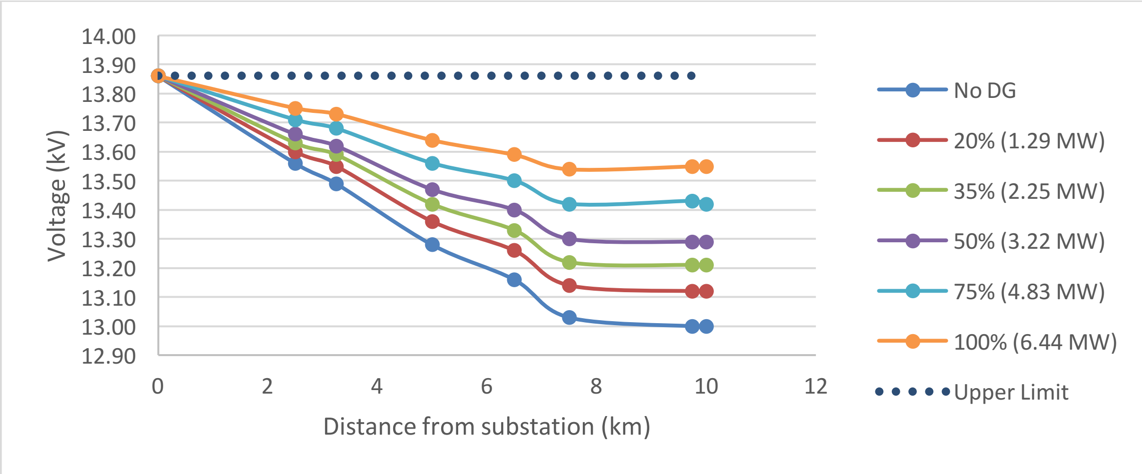

Figure 8: Voltage along the feeder with DG evenly distributed for 4pm-7pm

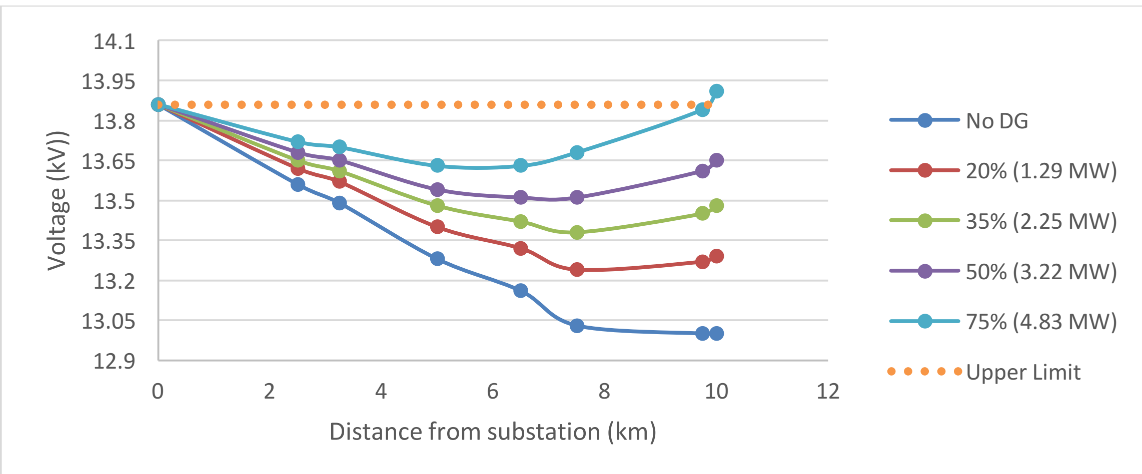

Figure 9: Voltage along the feeder with DG at end of feeder for 4pm-7pm

Table 11: Voltage improvement for the 4-7pm period, sunny day (evenly distributed DG)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.29 %	0.52 %	0.74 %	1.11 %	1.40 %
3.5	0.44 %	0.74 %	0.96 %	1.41 %	1.78 %
5	0.60 %	1.05 %	1.43 %	2.11 %	2.71 %
6.5	0.76 %	1.29 %	1.82 %	2.58 %	3.27 %
7.5	0.84 %	1.46 %	2.07 %	2.99 %	3.91 %
9.75	0.92 %	1.62 %	2.23 %	3.31 %	4.23 %
10	0.92 %	1.62 %	2.23 %	3.23 %	4.23 %

4.1.2. Case 2- Cloudy Day Voltage Regulation

In a cloudy day, the production is reduced. The most significant periods are from 8am to 11am, and 11am to 4pm. In Figure 10 when DG is evenly distributed up to 3.5 MW can be supplied between 8am and 11am. This penetration represents a voltage upgrade of 1.92% at end of the feeder, as shown in Table 12. Figure 11 shows that the maximum of the DG production can be integrated to the grid during the period from 11am to 4pm when DG is at end of the feeder. Table 13 presents that this injection to the grid can increase the voltage 2.25% at the end of the feeder. Appendix A.5 and B.5 contain the plots of voltage and percentages of improvement for voltage regulation on cloudy day.

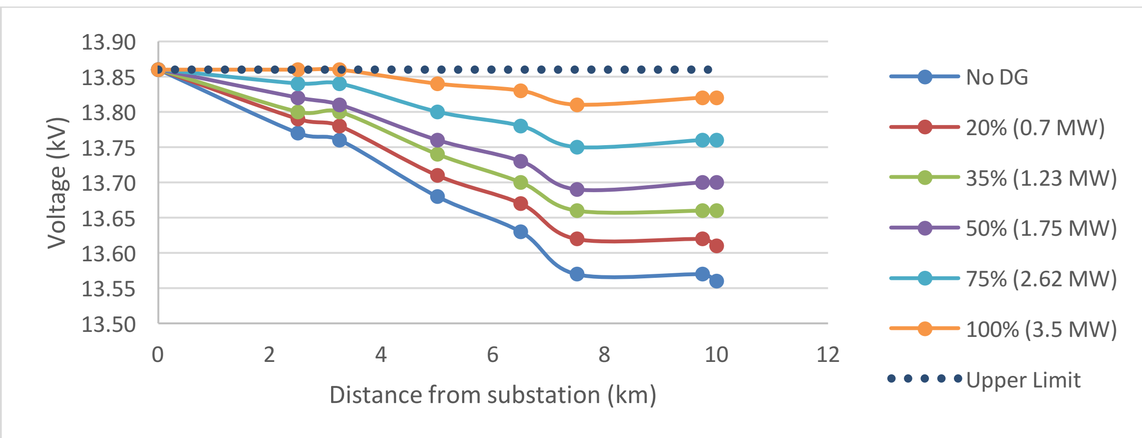

Figure 10: Voltage along the feeder with DG evenly distributed for 8am-11am

Table 12: Voltage improvement for the 8am-11am period, cloudy day (evenly distributed DG)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.15 %	0.22 %	0.36 %	0.51 %	0.65 %
3.5	0.15 %	0.36 %	0.36 %	0.58 %	0.73 %
5	0.22 %	0.58 %	0.58 %	0.88 %	1.17 %
6.5	0.29 %	0.73 %	0.73 %	1.10 %	1.47 %
7.5	0.37 %	0.88 %	0.88 %	1.33 %	1.77 %
9.75	0.37 %	0.96 %	0.96 %	1.40 %	1.84 %

10	0.37 %	1.03 %	1.03 %	1.47 %	1.92 %

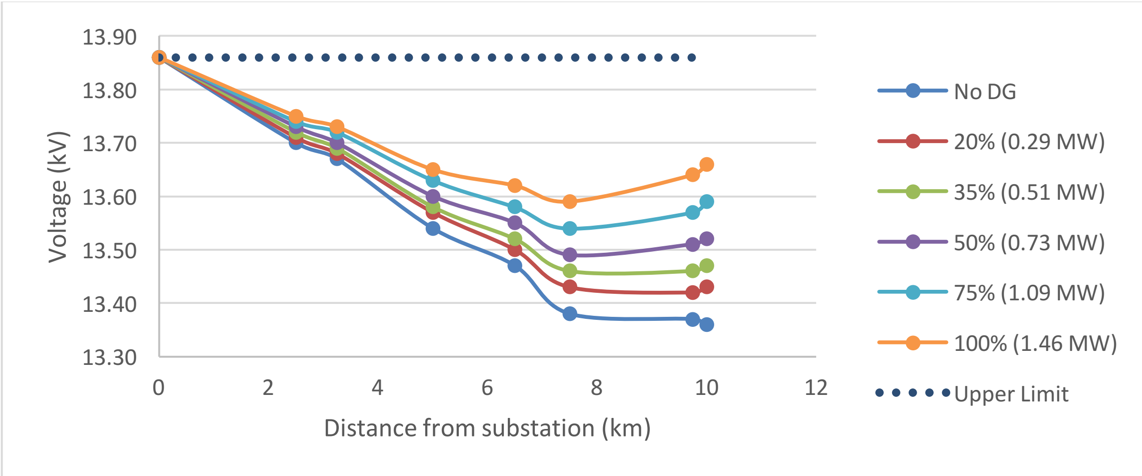

Figure 11: Voltage along the feeder with DG at end of feeder for 11am-4pm

Table 13: Voltage improvement for the 11am-4pm period, cloudy day (evenly distributed DG)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.07 %	0.15 %	0.22 %	0.29 %	0.36 %
3.5	0.07 %	0.15 %	0.22 %	0.37 %	0.44 %
5	0.22 %	0.30 %	0.44 %	0.66 %	0.81 %
6.5	0.22 %	0.37 %	0.59 %	0.82 %	1.11 %
7.5	0.37 %	0.60 %	0.82 %	1.20 %	1.57 %
9.75	0.37 %	0.67 %	1.05 %	1.50 %	2.39 %
10	0.52 %	0.82 %	1.20 %	1.72 %	2.25 %

4.2. Reactive Power Supply

For the reactive power supply study, simulations for a sunny and cloudy day were performed for the same periods. In addition, the simulations were performed using three different substation voltages: 1.05 p.u., 1.00 p.u. and 0.95 p.u. The next sections present the most representative cases. Further supporting results are presented in Appendices A.2, A.3 and A.4.

4.2.1. Case 3- Sunny Day with Reactive Supply- Voltage 1.05 p.u.

For the case of reactive supply with a voltage at the substation of 1.05 p.u., between 4am to 4pm, reactive power cannot be supplied from DG. On this period, DG can inject 35% (2.25 MVARs) of what can be generated and 20% (1.29 MVARs) if located at the end of the feeder. Figure 12 shows the results when DG is evenly distributed from 4pm to 7pm. These injections represent a voltage improvement of 3.92% when DG is evenly distributed and 4.23% when it is at the end of feeder. Tables 14 and 15 present the voltage improvement percentages for this case when DGs are evenly distributed and at end of feeder, respectively. Appendix B.2 contains the voltage improvement percentages for each period.

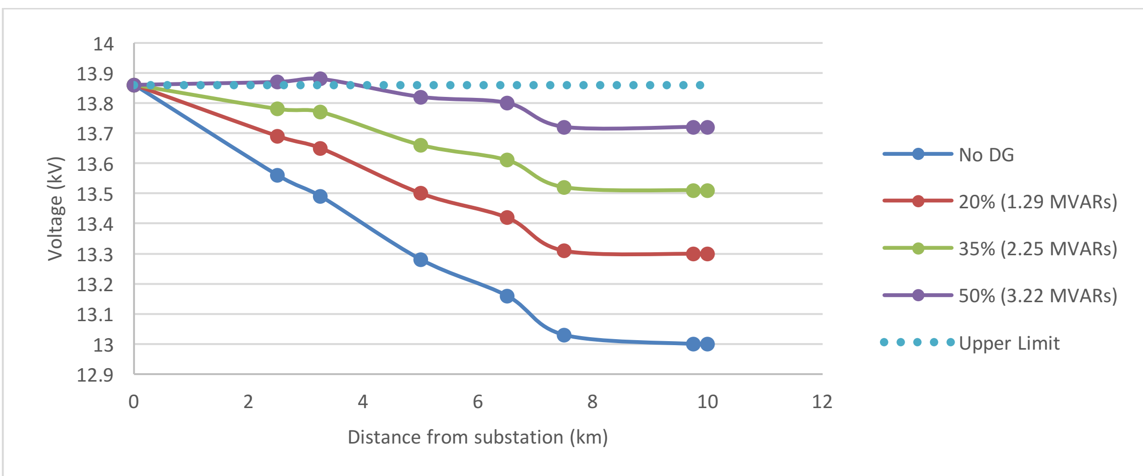

Figure 12: Voltage along the feeder with DG evenly distributed for 4pm-7pm

Table 14: Voltage improvement for reactive power supply for the 4pm-7pm period on sunny day with ***evenly distributed DG*** (1.05 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.96 %	1.62 %	*	*	*
3.5	1.19 %	2.08 %	*	*	*
5	1.66 %	2.86 %	*	*	*
6.5	1.98 %	3.42 %	*	*	*
7.5	2.15 %	3.76 %	*	*	*
9.75	2.31 %	3.92 %	*	*	*
10	2.31 %	3.92 %	*	*	*

Table 15: Voltage improvement for reactive power supply for the 4pm-7pm period on sunny day with ***DG at the end of the feeder*** (1.05 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.96 %	*	*	*	*
3.5	1.33 %	*	*	*	*
5	2.11 %	*	*	*	*
6.5	2.81 %	*	*	*	*
7.5	3.45 %	*	*	*	*
9.75	4.08 %	*	*	*	*
10	4.23 %	*	*	*	*

4.2.2. Case 4- Sunny Day with Reactive Supply- Voltage 1.00 p.u.

These simulations were made to confirm that a lower voltage at the substation would result in a higher penetration of reactive power without violating any ANSI voltage limits. Figure 13 shows the results of the simulation for the first hours of a sunny day, 4am to 8am, with DG at the end of the feeder, 1.54 MVARs were supplied. The simulations from this period when DG is evenly distributed also show that 1.54 MVARs could be supplied. These penetrations represent a voltage upgrade at end of the feeder of 2.75% when DG is evenly distributed and 5.05% when DG is at the end of the feeder. Tables 16 and 17 summarize the percentages for evenly distributed DG and at end of feeder, respectively.

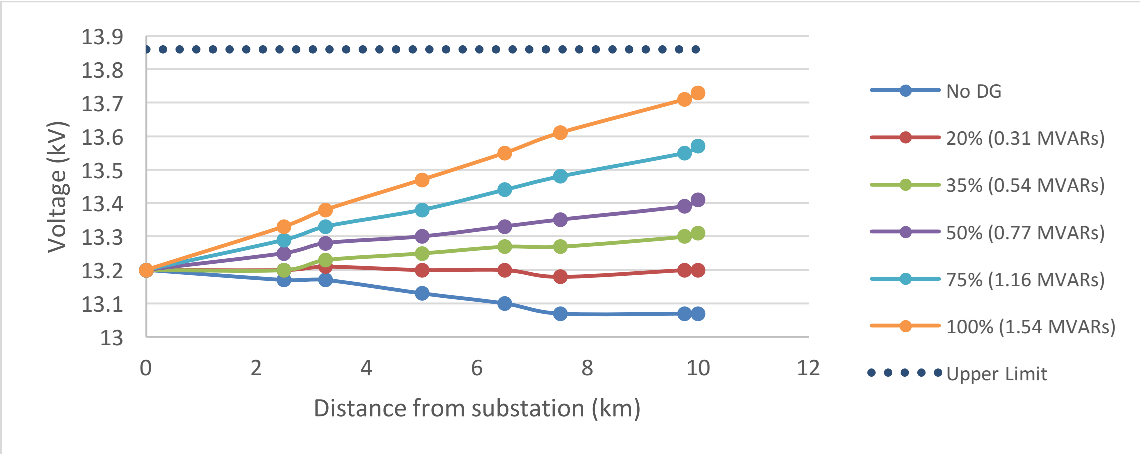

Figure 13: Voltage along the feeder with DG at end of feeder for 4am-8am with 1.00 p.u. voltage at substation

Table 16: Voltage improvement for reactive power supply for the 4am-8am period on sunny day with ***evenly distributed DG*** (1.00 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.23 %	0.38 %	0.61 %	0.91 %	1.21 %
3.5	0.30 %	0.53 %	0.76 %	1.14 %	1.44 %
5	0.38 %	0.69 %	0.99 %	1.52 %	2.06 %
6.5	0.53 %	0.92 %	1.22 %	1.83 %	2.44 %
7.5	0.54 %	0.92 %	1.30 %	1.99 %	2.68 %
9.75	0.54 %	0.99 %	1.38 %	2.07 %	2.75 %
10	0.54 %	0.99 %	1.38 %	2.07 %	2.75 %

Table 17: Voltage improvement for reactive power supply for the 4am-8am period on sunny day with ***DG at the end of the feeder*** (1.00 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.23 %	0.23 %	0.61 %	0.91 %	1.21 %
3.5	0.30 %	0.46 %	0.84 %	1.21 %	1.59 %
5	0.53 %	0.91 %	1.29 %	1.90 %	2.59 %
6.5	0.76 %	1.30 %	1.76 %	2.60 %	3.44 %

7.5	0.84 %	1.53 %	2.14 %	3.14 %	4.13 %
9.75	0.99 %	1.76 %	2.45 %	3.67 %	4.90 %
10	0.99 %	1.84 %	2.60 %	3.83 %	5.05 %

For the case when the sun is at its maximum point, which brings the opportunity for maximum DG production, less than 5.5 MVARs can be supplied for the evenly distributed case, as can be seen in Figure 14. This injection represents almost 7% of voltage increase at the end of the feeder, as shown in Table 18. Figure 15 shows a violation of the ANSI lower voltage limit for the case of No DG in the period of 4pm-7pm, but it is not taken into consideration, because the goal is to integrate DG to the grid. In this case, the DG can inject the maximum of what can be generated at that period, 6.44 MVARs. This penetration results in a significant voltage improvement, 10.43% at end of the feeder, as shown in table 19. All the voltage improvement percentage tables are presented in Appendix B.3.

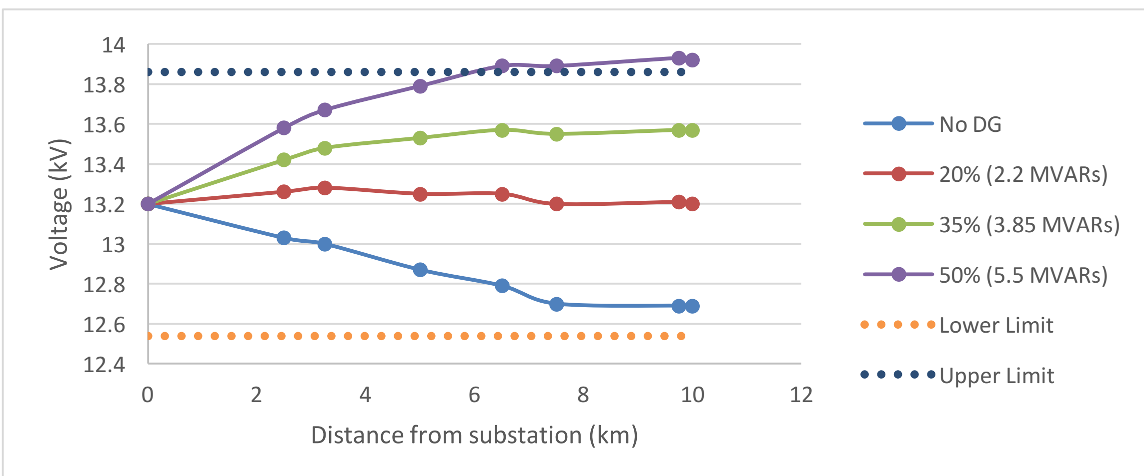

Figure 14: Voltage along the feeder with DG evenly distributed for 11am-4pm with 1.00 p.u. voltage at substation

Table 18: Voltage improvement for reactive power supply for the 11am-4pm period on a sunny day with ***evenly distributed DG*** (1.00 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.77 %	2.99 %	*	*	*
3.5	2.15 %	3.69 %	*	*	*
5	2.95 %	5.13 %	*	*	*
6.5	3.60 %	6.10 %	*	*	*
7.5	3.94 %	6.69 %	*	*	*
9.75	4.10 %	6.93 %	*	*	*
10	4.02 %	6.93 %	*	*	*

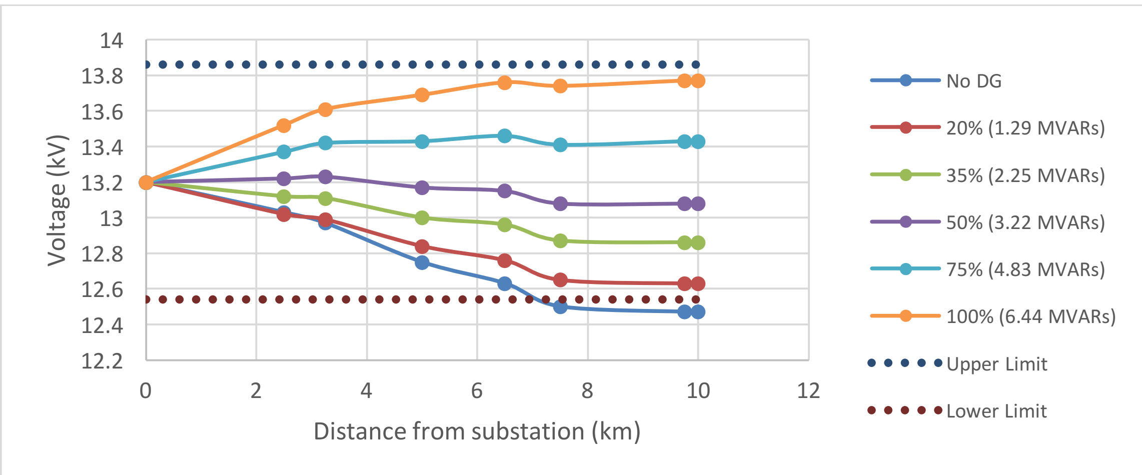

Figure 15: Voltage along the feeder with DG evenly distributed for 4pm-7pm with 1.00 p.u. voltage at substation

Table 19:Voltage improvement for reactive power supply for the 4pm-7pm period on a sunny day with ***evenly distributed DG*** (1.00 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.00 %	0.69 %	1.46 %	2.61 %	3.76 %
3.5	0.15 %	1.08 %	2.00 %	3.47 %	4.93 %
5	0.71 %	1.96 %	3.29 %	5.33 %	7.37 %
6.5	1.03 %	2.61 %	4.12 %	6.57 %	8.95 %
7.5	1.20 %	2.96 %	4.64 %	7.28 %	9.92 %
9.75	1.28 %	3.13 %	4.89 %	7.70 %	10.43 %
10	1.28 %	3.13 %	4.89 %	7.70 %	10.43 %

4.2.3. Case 5- Sunny Day with Reactive Supply- Voltage 0.95 p.u.

Decreasing the voltage at the substation to 12.54 kV (0.95 p.u.) produced the best results in terms of reactive power supply from the DGs. This is due to the fact that reactive power flows from locations with higher voltage levels to locations with lower voltage levels. Thus, if the DGs are to supply reactive power, the voltage at the substation needs to be lower than the voltage at the buses where DGs are located. Figure 16 shows the results for the period between 8am to 11am, the only violation is for lower voltage limit with No DG. With DG evenly distributed, and with the lower voltage permissible, the reactive power supply was 6.5 MVARs, the maximum of what DGs can produce on this period. This supply represents a voltage improvement of 12.29% at the end of the feeder, as can be seen in Table 20.

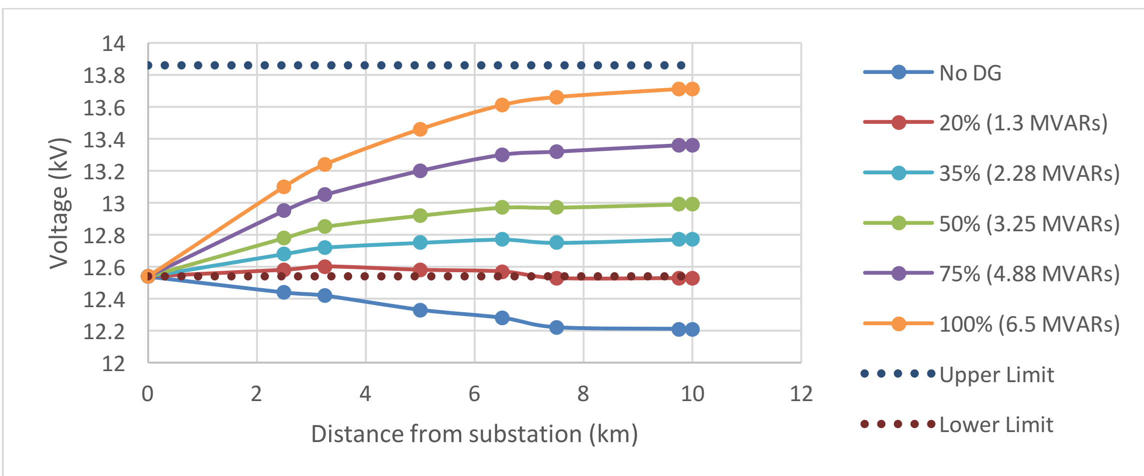

Figure 16: Voltage along the feeder with DG evenly distributed for 8am-11am with 0.95 p.u. voltage at substation

Table 20: Voltage improvement for reactive power supply for the 8am-11am period on a sunny day with ***evenly distributed DG*** (0.95 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.13 %	1.93 %	2.73 %	4.10 %	5.31 %
3.5	1.45 %	2.42 %	3.46 %	5.07 %	6.60 %
5	2.03 %	3.41 %	4.79 %	7.06 %	9.16 %
6.5	2.36 %	3.99 %	5.62 %	8.31 %	10.83 %
7.5	2.54 %	4.34 %	6.14 %	9.00 %	11.78 %
9.75	2.62 %	4.59 %	6.39 %	9.42 %	12.29 %
10	2.62 %	4.59 %	6.39 %	9.42 %	12.29 %

The period of 11am to 4pm, presented in Figure 17, when the DG output can reach its maximum installed capacity, about 75% (8.25 MVARs) can be reactive power when evenly distributed. Table 21 shows a voltage upgrade of 15.57% at the end of feeder for this supply. Figure 18 shows the 4pm to 7pm period, where there is violation of lower voltage limit for the cases of No DG and 20% of DG at end of feeder. There is no violation of voltage limits from a little more than 35% and less than 100% of what DG can produce in this period (6.44 MVARs). For the case when DG is evenly distributed, there is a lower voltage limit violation for penetration of DG (lower than 50%), and it can supply the maximum reactive power of what can be generated in this period. The 4.83 MVARs injection causes a voltage improvement of 17.18% at the end of the feeder as is shown in Table 22. Appendix B.4 shows percentage of voltage improvement for all the periods in this case.

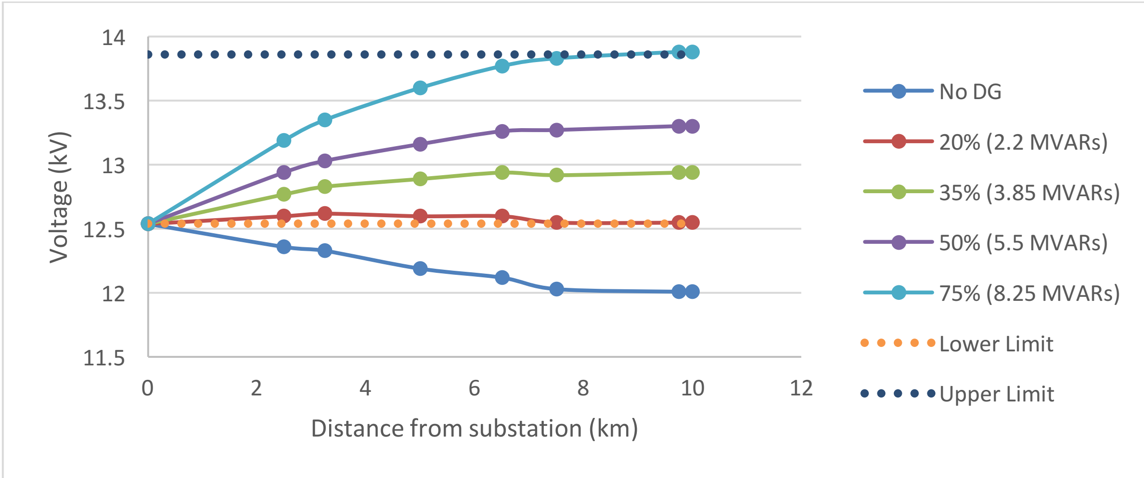

Figure 17: Voltage along the feeder with DG evenly distributed for 11am-4pm with 0.95 p.u. voltage at substation

Table 21: Voltage improvement for reactive power supply for the 11am-4pm period on a sunny day with ***evenly distributed DG*** (0.95 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.94 %	3.32 %	4.69 %	6.72 %	*
3.5	2.35 %	4.06 %	5.68 %	8.27 %	*
5	3.36 %	5.74 %	7.96 %	11.57 %	*
6.5	3.96 %	6.77 %	9.41 %	13.61 %	*
7.5	4.32 %	7.40 %	10.31 %	14.96 %	*
9.75	4.50 %	7.74 %	10.74 %	15.57 %	*
10	4.50 %	7.74 %	10.74 %	15.57 %	*

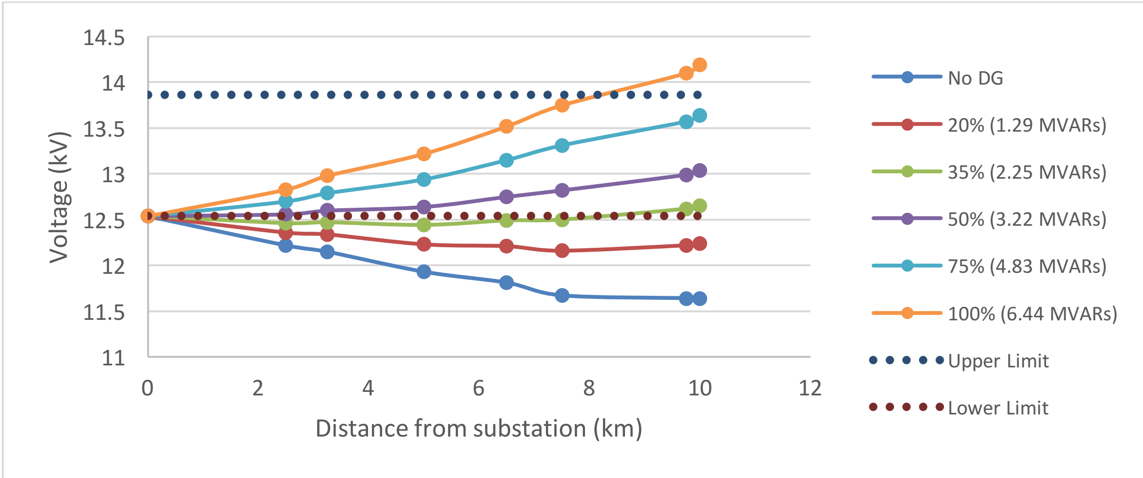

Figure 18: Voltage along the feeder with DG at end of feeder for 4pm-7pm with 0.95 p.u. voltage at substation

Table 22: Voltage improvement for reactive power supply for the 4pm-7pm period on a sunny day with DG at ***end of the feeder*** (0.95 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.13 %	1.94 %	2.75 %	3.88 %	*
3.5	1.56 %	2.63 %	3.70 %	5.27 %	*
5	2.51 %	4.27 %	5.95 %	8.47 %	*
6.5	3.39 %	5.76 %	7.96 %	11.35 %	*
7.5	4.20 %	7.11 %	9.85 %	14.05 %	*
9.75	4.98 %	8.42 %	11.60 %	16.58 %	*
10	5.15 %	8.68 %	12.03 %	17.18 %	*

4.2.4. Case 6- Cloudy Day with Reactive Supply- Voltage 1.05 p.u

On a cloudy day, as for the voltage regulation case, there is not much reactive power generated. The most significant cases are the periods between 8am to 11am, and 11am to 4pm. For the case of DG at the end of the feeder between 8am to 11am, 0.7 MVARs are supplied (Figure 19). This supply cause 2.14% of voltage increase for this case at end of the feeder, as shown in Table 23.

For the case when DG is evenly distributed between 11am to 4pm, 1.46 MVARs can be supplied. For the case when DG is at the end of the feeder, the reactive power supplied must be less than 1.46 MVARs (100%), as shown in Figure 20. Table 24 shows for an injection of 1.09 MVARs (75%), there is a voltage upgrade of 3.52% at the end of the feeder for this case. All the voltage improvement percentages for this case are presented in Appendix B.6.

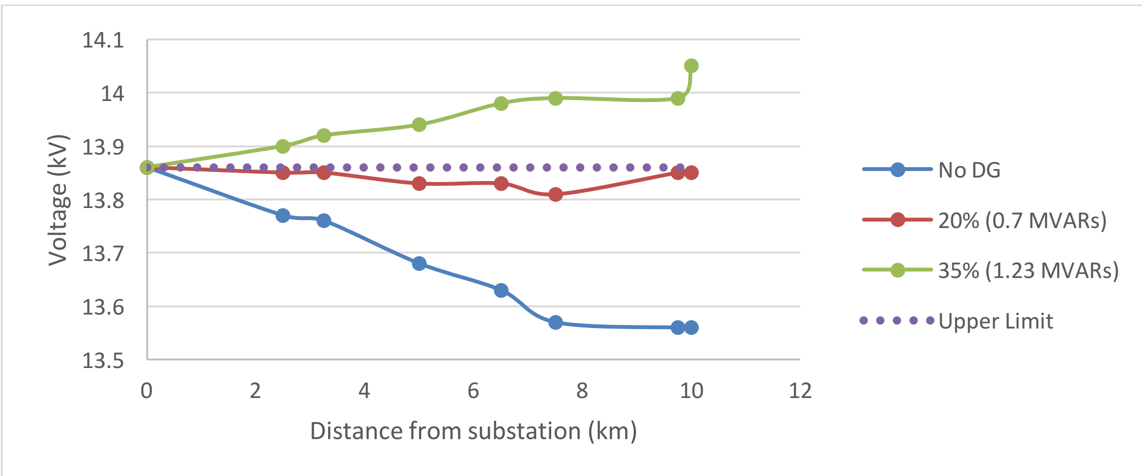

Figure 19: Voltage along the feeder with DG at end of feeder for 8am-11am with 1.05 p.u. voltage at substation on cloudy day

Table 23: Voltage improvement for reactive power supply for the 8am-11am period on a cloudy day with DG at ***end of the feeder*** (1.05 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.58 %	*	*	*	*
3.5	0.65 %	*	*	*	*
5	1.10 %	*	*	*	*
6.5	1.47 %	*	*	*	*
7.5	1.77 %	*	*	*	*
9.75	2.14 %	*	*	*	*
10	2.14 %	*	*	*	*

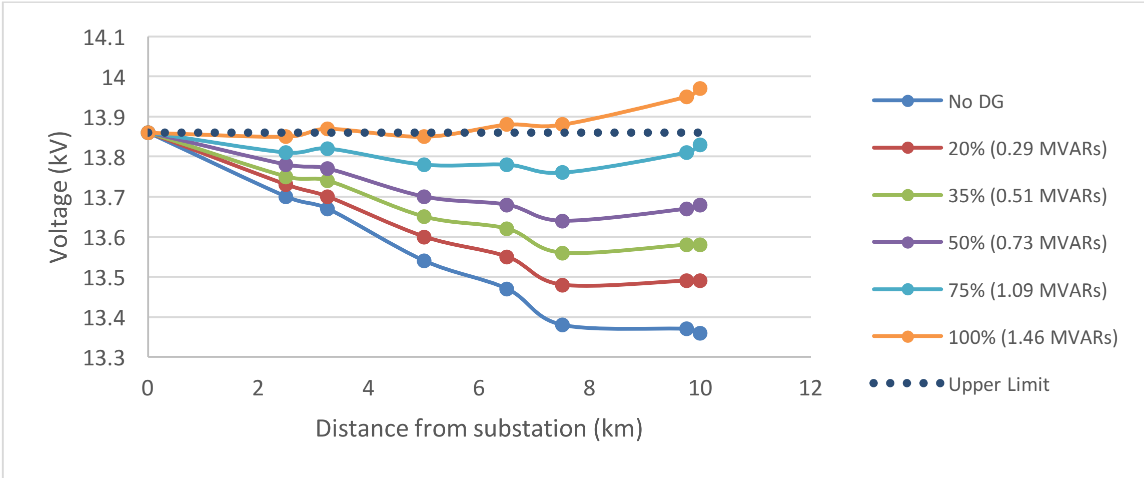

Figure 20: Voltage along the feeder with DG at end of feeder for 11am-4pm with 1.05 p.u. voltage at substation on cloudy day

Table 24: Voltage improvement for reactive power supply for the 11am-4pm period on a cloudy day with DG at ***end of the feeder*** (1.05 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.22 %	0.36 %	0.58 %	0.80 %	*
3.5	0.22 %	0.51 %	0.73 %	1.10 %	*
5	0.44 %	0.81 %	1.18 %	1.77 %	*
6.5	0.59 %	1.11 %	1.56 %	2.30 %	*
7.5	0.75 %	1.35 %	1.94 %	2.84 %	*
9.75	0.90 %	1.57 %	2.24 %	3.29 %	*
10	0.97 %	1.65 %	2.40 %	3.52 %	*

4.2.5. Case 7- Cloudy Day with Reactive Supply- Voltage 1.00 p.u.

The results of reactive supply with a substation voltage of 1.00 p.u. (13.2 kV), on a cloudy day are shown in Figures 21 to 23. Figure 21 shows the results for the case when DG is evenly distributed between 8am to 11am, the reactive power supply can be 3.5 MVARs, the maximum of what can be generated. The voltage improvement at the end of feeder for this injection is 6.29%, as shown in Table 25. For the simulation period of 11am to 4pm, when DG is evenly distributed

1.46 MVARs can be supplied, as can be seen in Figure 22. Table 26 shows the voltage improvement for this period. For maximum penetration, the end of feeder has an improvement of 2.44%.

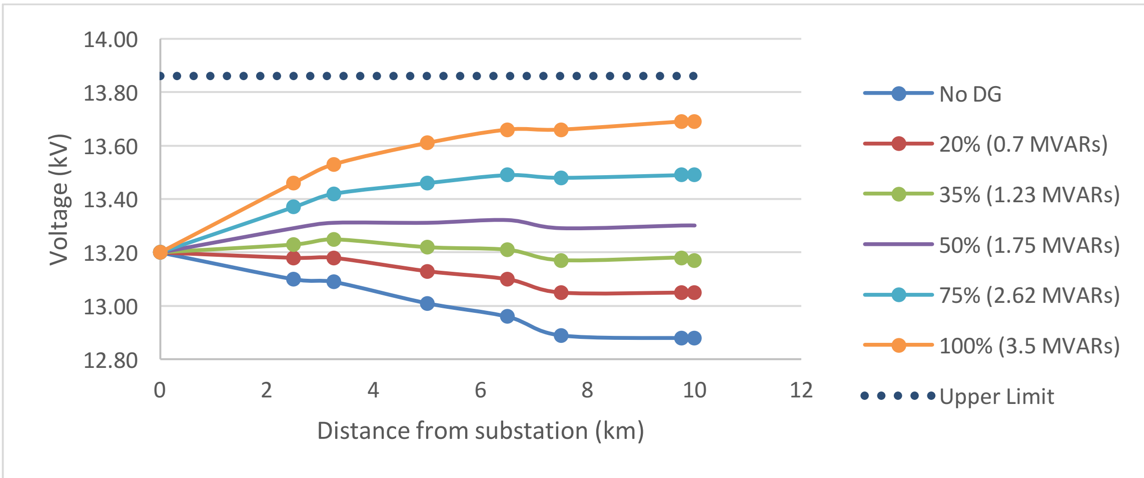

Figure 21: Voltage along the feeder with DG evenly distributed for 8am-11am with 1.00 p.u. voltage at substation on cloudy day

Table 25: Voltage improvement for reactive power supply for the 8am-11am period on a cloudy day with ***evenly distributed DG*** (1.00 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.61 %	0.99 %	1.45 %	2.06 %	2.75 %
3.5	0.69 %	1.22 %	1.68 %	2.52 %	3.36 %
5	0.92 %	1.61 %	2.31 %	3.46 %	4.61 %
6.5	1.08 %	1.93 %	2.78 %	4.09 %	5.40 %
7.5	1.24 %	2.17 %	3.10 %	4.58 %	5.97 %
9.75	1.32 %	2.33 %	3.26 %	4.74 %	6.29 %
10	1.32 %	2.25 %	3.26 %	4.74 %	6.29 %

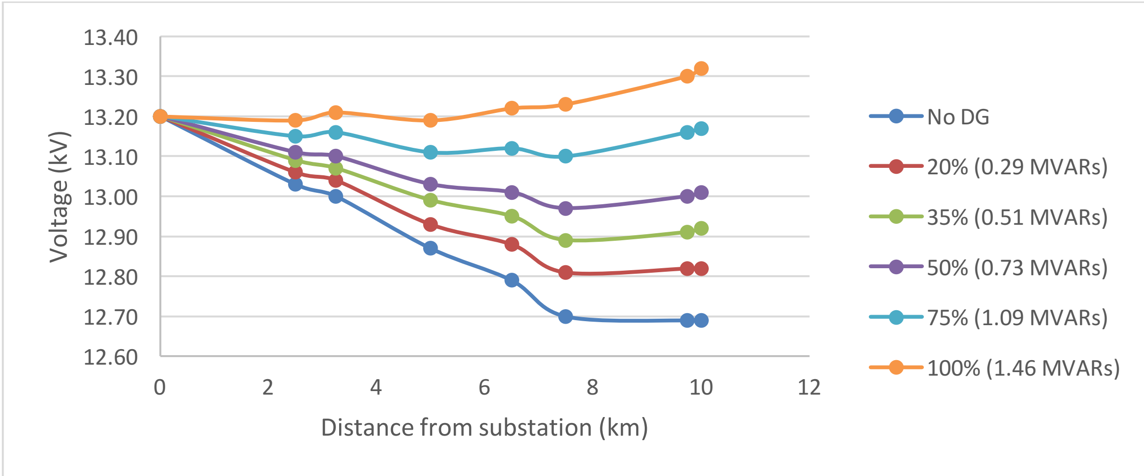

Figure 22: Voltage along the feeder with DG evenly distributed for 11am-4pm with 1.00 p.u. voltage at substation on cloudy day

Table 26: Voltage improvement for reactive power supply for the 11am-4pm period on a cloudy day with ***evenly distributed DG*** (1.00 p.u.)

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.23 %	0.38 %	0.54 %	0.77 %	1.00 %
3.5	0.23 %	0.46 %	0.62 %	0.92 %	1.31 %
5	0.39 %	0.62 %	0.85 %	1.40 %	1.79 %
6.5	0.47 %	0.70 %	1.02 %	1.56 %	2.19 %
7.5	0.55 %	0.79 %	1.18 %	1.81 %	2.44 %
9.75	0.47 %	0.79 %	1.18 %	1.81 %	2.44 %
10	0.55 %	0.87 %	1.26 %	1.81 %	2.44 %

For the period of 4pm to 7pm, there is an ANSI violation of lower voltage limit for all the penetration levels (Figure 23). Appendix B.7 presents all the tables for voltage improvement percentages for this case.

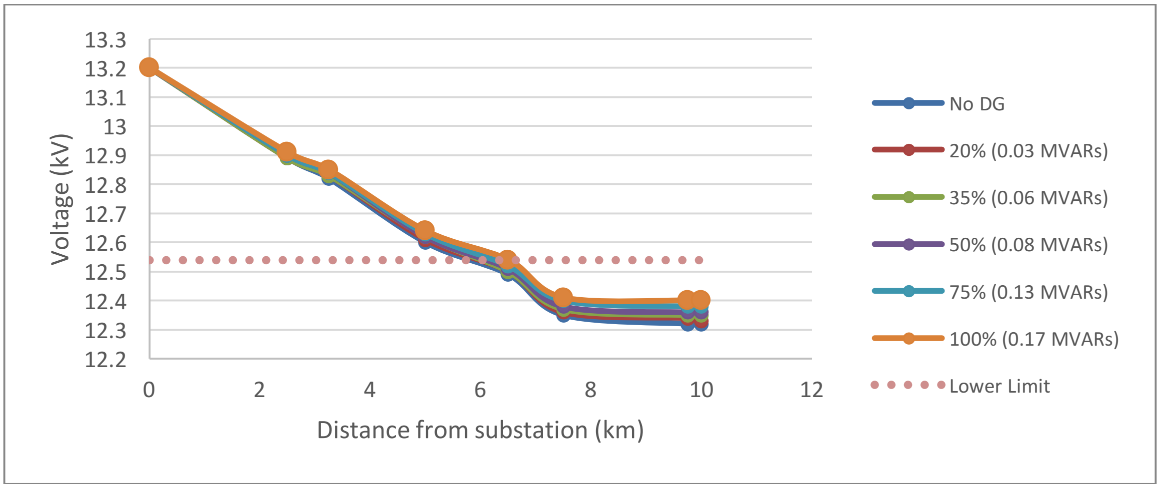

Figure 23: Voltage along the feeder with DG at end of feeder for 4pm-7pm with 1.00 p.u. voltage at substation on cloudy day

4.3. Cost of active and reactive power from PV-DG

In Puerto Rico, at least since 2012, rooftop PV achieved grid-parity or less. A Rooftop Solar Challenge report from UPRM (funded through a DOE SunShot initiative) concluded that in the Mayaguez area, using \$3 per watt as installation cost, and with 4.5 hours of peak sun on average, the LCOE is around 11.5 cents per kWh. Even with some costs were added to the rooftop PV over the \$0.115/kWh mentioned above, the rooftop PV costs in Puerto Rico could be in a range from \$2/MWh to \$3/MWh (using as basis that the value from grid power found in literature was \$3 per MWh). That range was assumed in the OPF studies conducted for this thesis.

The results of producing active and reactive power from PV-DG were analyzed using the OPF approach described in Section 3.3 and implemented in MATLAB. The same cases as the simulation of DiGSILENT were studied to see the effect on marginal costs in dollars per MVA of providing those services to the grid. The results of the MATLAB simulations gave a marginal cost (\$/MWh or \$/MVARh) for each bus of the system. The marginal costs per bus vary because the segments between buses are different. For more details, the tables with the marginal costs and the costs per buses are available in Appendix C.

4.3.1. Cost of active power from PV-DG

In this study, the main goal was to determine how much the injection of active power to the grid cost, for different hour-periods of the day, presented in the previous section of voltage regulation results. All the cases showed a decrease of marginal cost as the PV penetration increases (supporting evidence presented in Appendix A). For the period of 4am to 8am, the generation and demand, both are small. From Table 27, it can be seen that the PV-DG marginal cost per bus in the main feeder varies between \$3.19/MWh to \$8.28/MWh; the marginal cost in laterals is in a range between \$3.21/MWh to \$3.28/MWh.

Table 27: Active power marginal cost per bus for 4am to 8am

Distance	No DG (\$/MWh)	20% DG (\$/MWh)
0 km	3.203	3.188
2 km	3.221	3.204
3.5 km	3.229	3.211
5 km	3.246	3.227
6.5 km	3.267	3.246
7.5 km	3.293	3.270
9.75 km	3.300	3.276
10 km	3.300	3.277
Half Lat. 1	3.224	3.207
End Lat. 1	3.225	3.208
Half Lat. 2	3.250	3.231
End Lat. 2	3.251	3.232
Half Lat. 3	3.297	3.274
End Lat.3	3.298	3.275

From the results of the active supply from DIgSILENT, the maximum of injection from DG to grid during the period of 8am to 11am is 50% of what it can produce during these hours.

The OPF results of the different percentages of injection (20%, 35% and 50%) show that the cost decreases slightly with more injection. From the beginning of the main feeder, the marginal cost decreases from $3.22/MWh to $3.12/MWh.; at the end of the feeder the marginal cost decreases from $3.29/MWh to $3.19/MWh. The end of the laterals has a decrease from $3.23/MWh to $3.18/MWh. Appendix C.1.2 present all the results for this period.

Table 28 presents the marginal cost for the period of maximum possible generation, the period from 11am to 4pm. From the simulations presented in section 4.1.1, only 50% of the available generation could be supplied to the grid without any ANSI violations. This period also has an increase on demand compared to the previous periods, which means that also the cost will increase. From the near substation bus, the marginal cost obtained from the OPF study varies from $3.28/MWh to $3.12/MWh; at end of the main feeder, the cost varies from $3.30/MWh to $3.19/MWh; and the laterals end have a variation from $3.43/MWh to $3.18/MWh.

Table 28: Active power marginal cost per bus for 11am-4pm

Distance	No DG ($/MWh)	20% DG ($/MWh)	35% DG ($/MWh)	50% DG ($/MWh)
0 km	3.287	3.219	3.172	3.123
2 km	3.812	3.238	3.187	3.133
3.5 km	3.324	3.247	3.194	3.138
5 km	3.35	3.267	3.210	3.150
6.5 km	3.38	3.289	3.228	3.163
7.5 km	3.419	3.320	3.252	3.182
9.75 km	3.43	3.328	3.259	3.187
10 km	3.43	3.328	3.259	3.187
Half Lat. 1	3.318	3.242	3.189	3.134
End Lat. 1	3.319	3.243	3.190	3.135
Half Lat. 2	3.356	3.271	3.212	3.151
End Lat. 2	3.357	3.272	3.214	3.152
Half Lat. 3	3.425	3.323	3.254	3.182
End Lat.3	3.427	3.325	3.255	3.184

The period from 4pm to 7pm, is one of the peak demand periods. Due to the high demand, the simulations of DIgSILENT showed that all the DG output could be injected to the grid without voltage violations. The marginal costs from the OPF simulations vary from \$3.47/MWh to \$3.20/MWh at the beginning of the feeder, near substation; at the end of the main feeder the marginal cost decreases from \$3.72/MWh to \$3.32/MWh; and for the laterals ends, the marginal cost varies from \$3.72/MWh to \$3.31/MWh. Further results for this period are presented in Appendix C.1.4

4.3.2. Cost of reactive power from PV-DG

The main objective of this section is to estimate the costs of supplying reactive power from PV-DG. The reactive power from DG is becoming an important ancillary service from DG. If the DG can provide this service to the grid, it can be helpful for emergency or grid-congested situations. The cost of providing reactive power is less in comparison with the cost of provide active power. The range of the active power is in dollars (\$/MWh), and the range of reactive power is in cents (¢/MVARh). The reactive power simulations from DIgSILENT were used as reference to analyze the costs of providing the service using the OPF simulations.

The demand of reactive power can be less than possible PV-DG generation, because that excess of reactive power generation is assumed to be absorbed by the substation. For those cases where the generation is greater than demand, the substation will absorb the excess of reactive generation. A difference between the cost of active and reactive power is that the cost increases as generation increases, and also increases as it moves away from substation.

For the case between 4am to 8am, the results from the simulations of DIgSILENT showed that DGs can inject the maximum of what can be produced during this period. In the OPF simulations the marginal costs for reactive supply without DGs, show negative values. In this period, the grid it is not supplying the reactive power. Without DGs, all the reactive power loads are supplied by the capacitor banks installed on the feeder (because of the way the OPF program works, these costs are shown as negative as if the capacitors were privately-owned). Table 29 shows that at the end of feeder for the period from 4am to 8am, with DG injection, the marginal cost varies from 0.16 cents/MVARh to 4.4 cents/MVARh. The laterals marginal costs for PV-DG vary from 1.6 cents/MVARh to 4.5 cents/MVARh.

Table 29: Reactive power marginal cost per bus for 4am-8am

Distance	No DG ($/MVARh)	20% DG ($/MVARh)	35% DG ($/MVARh)	50% DG ($/MVARh)	75% DG ($/MVARh)	100% DG ($/MVARh)
0 km	-	-	-	-	-	-
2 km	-0.001	-0.002	-0.003	-0.005	-0.006	-0.008
3.5 km	-0.002	-0.004	-0.006	-0.008	-0.01	-0.012
5 km	-0.003	-0.006	-0.008	-0.011	-0.015	-0.018
6.5 km	-0.005	-0.009	-0.013	-0.017	-0.022	-0.028
7.5 km	-0.010	-0.016	-0.021	-0.026	-0.034	-0.041
9.75 km	-0.009	-0.016	-0.020	-0.026	-0.034	-0.042
10 km	-0.009	-0.016	-0.020	-0.026	-0.034	-0.042
Half Lat. 1	0.000	-0.002	-0.004	-0.005	-0.008	-0.010
End Lat. 1	0.000	-0.002	-0.003	-0.005	-0.007	-0.010
Half Lat. 2	-0.002	-0.006	-0.008	-0.012	-0.016	-0.020
End Lat. 2	-0.002	-0.005	-0.008	-0.011	-0.016	-0.020
Half Lat. 3	-0.009	-0.016	-0.021	-0.027	-0.035	-0.043
End Lat.3	-0.001	-0.016	-0.021	-0.027	-0.035	-0.043

Table 30 presents the marginal costs of providing this service by PV-DG for the period from 8am to 11am. Near the substation varies from 0.5 cents/MVARh to 2.9 cents/MVARh; at end of the main feeder it varies from 3.1 cents/MVARh to 14.8 cents/MVARh; and the laterals marginal costs vary from 3.1 cents/MVARh to 15.1 cents/MVARh. All these costs, as explained before, are what the grid would pay to the DG for supplying a unit of this service.

Table 30: Reactive power marginal cost per bus for 8am-11am

Distance	No DG ($/MVARh)	20% DG ($/MVARh)	35% DG ($/MVARh)	50% DG ($/MVARh)	75% DG ($/MVARh)	100% DG ($/MVARh)
0 km	-	-	-	-	-	-
2 km	0.001	-0.005	-0.010	-0.014	-0.022	-0.029
3.5 km	0.000	-0.008	-0.016	-0.022	-0.032	-0.043
5 km	0.002	-0.012	0.023	-0.033	-0.050	-0.067
6.5 km	0.002	-0.019	-0.034	-0.048	-0.076	-0.100
7.5 km	-0.003	-0.030	-0.050	-0.069	-0.105	-0.140
9.75 km	-0.001	-0.031	-0.052	-0.072	-0.111	-0.148
10 km	-0.001	-0.031	-0.052	-0.072	-0.110	-0.148
Half Lat. 1	0.002	-0.006	-0.013	-0.019	-0.029	-0.039
End Lat. 1	0.002	-0.006	-0.013	-0.018	-0.028	-0.038
Half Lat. 2	0.002	-0.013	-0.026	-0.037	-0.057	-0.077
End Lat. 2	0.003	-0.013	-0.026	-0.037	-0.057	-0.076
Half Lat. 3	-0.002	-0.031	-0.053	-0.074	-0.112	-0.151
End Lat.3	-0.002	-0.031	-0.053	-0.074	-0.111	-0.150

The period of maximum solar irradiance, when DG can produce its maximum capacity, the reactive power supply can be just 50% of the DG available capacity. The marginal cost from the OPF for the maximum solar irradiance period is presented in Table 31. Near the substation, with DG injection, the marginal cost has a range from 0.7 cents/MVARh to 2.4 cents/MVARh; from 4.2 cents/MVARh to 12.2 cents/MVARh at the end of main feeder; and from 0.9 cents/MVARh to 12.4 cents/MVARh at laterals ends.

Table 31: Reactive power marginal cost per bus for 11am-4pm

Distance	No DG ($/MVARh)	20% DG ($/MVARh)	35% DG ($/MVARh)	50% DG ($/MVARh)
0 km	-	-	-	-
2 km	0.003	-0.007	-0.016	-0.024
3.5 km	0.004	-0.011	-0.024	-0.035
5 km	0.007	-0.017	-0.036	-0.055
6.5 km	0.008	-0.026	-0.054	-0.083
7.5 km	0.006	-0.041	-0.078	-0.116
9.75 km	0.008	-0.042	-0.081	-0.122
10 km	0.008	-0.042	-0.081	-0.122
Half Lat. 1	0.004	-0.009	-0.021	-0.031
End Lat. 1	0.005	-0.009	-0.021	-0.031
Half Lat. 2	0.008	-0.019	-0.042	-0.063
End Lat. 2	0.008	-0.019	-0.041	-0.063
Half Lat. 3	0.008	-0.043	-0.083	-0.124
End Lat.3	0.008	-0.043	-0.083	-0.124

On one of the peak demand periods, from 4pm to 7pm, the cost of supplying reactive power to the grid is the most expensive than the previous periods. If it is supplied from the grid, it costs from 0.8 cents/MVARh to 2.4 cents/MVARh. If the DG will supply it, its costs vary from 0.1 cents/MVARh to 2.7 cents/MVARh near substation; 0.7 cents/MVARh to 13.4 cents/MVARh at the end of the main feeder; and from 0.9 cents/MVARh to 13.7 cents/MVARh at laterals ends. Appendix C.2 presents all the other tables for marginal costs for reactive power supply for each period.

4.4. Analysis

The main purpose of this thesis was to analyze the costs of some services DG can bring to the grid. The investigation focused on supplying active and reactive power, which helps to reduce the power supplied by the grid and helps with voltage regulation.

The study of how much real and reactive power can be injected to the grid gives an idea of how much these services benefit the system. Figure 24, 25 and 26 show some of the results of the simulations.

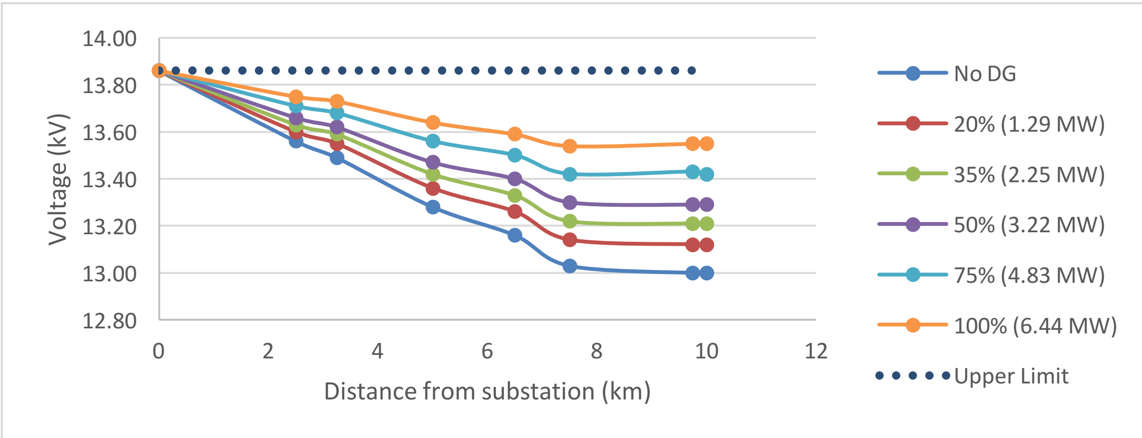

Figure 24: Voltage along the feeder with DG evenly distributed for 4pm-7pm for real power production

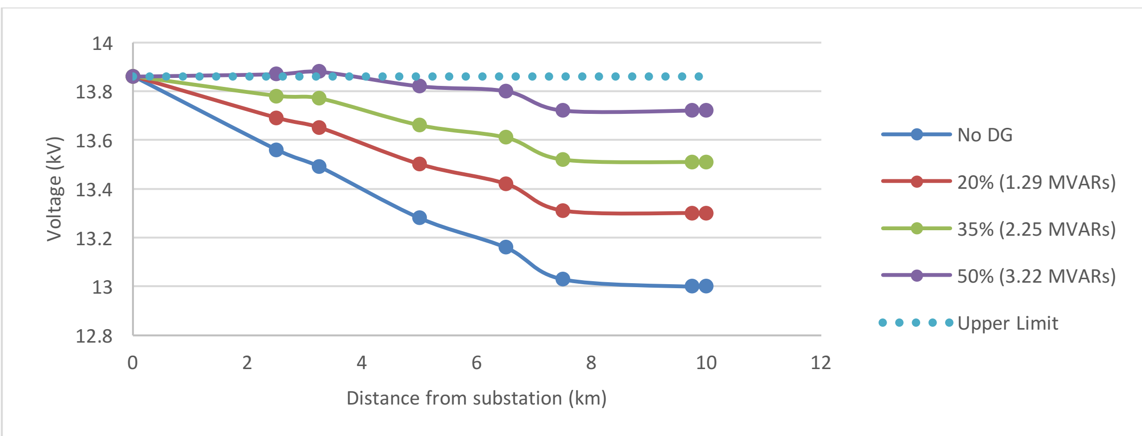

Figure 25: Voltage along the feeder with DG evenly distributed for 4pm-7pm for reactive power production

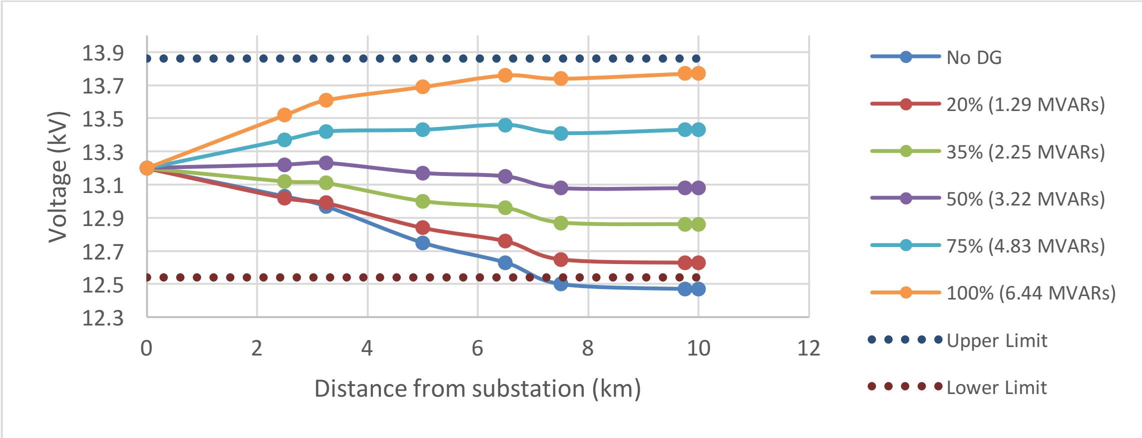

Figure 26: Voltage along the feeder with DG evenly distributed for 4pm-7pm for reactive power production with 1.0 p.u. voltage at substation

When the PV-DG is delivering real power, it can inject 6.44 MW in the period from 4pm to 7pm, as can be seen in Figure 24. In the case when it is delivering only reactive power, it only can inject almost the 3.22 MVARs; 50% of what it can produce (Figure 25). This comparison gives an idea of the effect of reactive power as voltage increases. To maximize the reactive power supply benefit, the substation voltage is reduced to 1.0 p.u. to inject more reactive power from the DGs. Figure 26 shows that with the substation voltage at 1.0 p.u., the voltage almost reaches the maximum voltage limit by ANSI C84 Standard. Both services give the benefit of improving voltage.

In Puerto Rico, the rooftop PV works with power factor of 1. This setting fixes the DG generation only to real power production. This thesis showed that PV-DG can bring both services, real and reactive power to the grid; and both bring improvements to the system voltage. Adjusting this setting to other power factors, e.g., 0.95 power factor, the PV-DG can bring both services, and the reactive power can be supplied to other customers, and can have less impact on the system than when it supplies only real power. Furthermore, the losses associated with supplying reactive power from the grid would be diminished if reactive power is supplied locally. On the other hand, if there is an abnormal condition on the system, and the substation has a 0.95 p.u. voltage, this thesis also showed that DGs can increase their injection of reactive power, to improve the voltage and help to reach a more stable voltage level on the feeder.

For the case of voltage regulation, when DG supplies only active power, when DG is evenly distributed on a sunny day, DG can inject 50% of what it can produce on some periods, but in other cases it can inject all of its production without violating voltage limits. This injection results in a voltage improvement up to 4.23%. The marginal cost for active power supply from the grid per bus was approximately \$3.40/MWh; and the marginal cost form DG per bus was approximately \$3.24/MWh. On the early hours, from 4am to 8am, the average cost per section of supply from the grid is \$3.25/MWh; supplying it from DG would cost \$3.24/MWh. For the period of peak sun, the cost is the most expensive period. The grid's average marginal cost was \$3.70/MWh per section; and the supply by the DG is \$3.54/MWh.

From these results, as DG penetration increases, the marginal cost decreases. A new alternative is to assign values to the services DG brings to grid, including voltage regulation. If the solar- kWh credit for DG owners is to be decreased (e.g., a revision of net metering rates), the DG services need to be accounted for in order for the changes to be fair. With more integration of DG, the costs decrease, and DGs would bring voltage support to the grid and need to be compensated accordingly.

The reactive power supply also brings voltage improvement to the system. This effect varies depending on the period and allocation of DG, but it can improve the voltage up to 17% on the peak demand period when the voltage at substation is downgrade to 0.95 p.u.

For the reactive supply, marginal cost analysis is more complex. This service, as mentioned in the literature review, is neglected in the economic analysis of marginal prices. On this study, the DG can supply a significant percentage of the reactive power demand, if needed. The marginal cost of providing reactive power that the grid would pay to DG between 4am to 11am is from 0.1 cents to 15.1 cents per MVARh. From 11am to 4pm, the marginal cost would be from 0.3 cents to 12.4 cents per MVARh. The period between 4pm to 7pm, the grid would pay to DG for supplying reactive between 0.1 cents to 13.7 cents per MVARh. The reactive marginal cost per kVAR compares to the average cost for reactive supply by capacitors, reactor and Super-VAR. This means it could be a benefit for the utility if the DG can supply the reactive power if there is an urgent need.

With grid data from PR, the OPF analysis could be more representative of costs. However, the results obtained are valid since they show a trend of the expected costs and validate the need to fairly compensate for services provided by DG.

In Puerto Rico, the DG customers are under the Net Metering Program. This program, as mentioned before, is under revision in some states, and other are adopting new programs to incentive the DG customers because this program tends to benefit the DG customers and affect the utility. Eventually, Puerto Rico will need another program that can be beneficial to both sides: utility and customer. From the literature, and the results of the study, one of the options can be to decrease the credit of kWh, and assign an incentive to provide kVAR when it is needed, without affecting the benefits of the DG customer. The results showed some general trends on how to determine what the utility should pay to DG for reactive power supply, in different ranges depending on the period of the day. An alternative, as mentioned for the case of voltage regulation is to decrease the value for kWh and give appropriate credit for DG services. However, the experience in other places shows that this kind of changes to net metering should occur when DG participation is over 5%, which is not true in Puerto Rico as of May 2017.

4.5. Rate Design Proposal

The ratemaking process is complex and challenging. With the increase in renewable distributed generation penetration, it becomes more difficult to design a fair and effective rate, which benefits the utility and customer. The use of marginal costs can make the rate tariff more accurate and fair as mentioned before on Chapter 2. The main purpose of this thesis was study two of the services DG can bring to the grid, voltage regulation and reactive power supply, and what possible prices could be assigned to them. These ancillary services have traditionally been grouped as one, and the utilities assign a charge to them. It is time that the ancillary services DG can bring to the grid will be maximized. The marginal cost of voltage regulation by DG on this study was an average between \$2/MWh to \$3/MWh. The reactive marginal cost varies from 0 cents/MWh to 5 cents/MWh. The case of reactive power supply by DG, the reactive marginal cost varies from 1 cents/MWh to 10 cents/MWh. These values are just starting points that require further analysis. For example, what is the value of deferring capital improvements to the grid because the DGs are providing these services? What is the proper value to the grid of the DGs providing these services during emergency or grid congestion conditions? A better model, more accurate, for solar PV is also needed to yield more accurate cost results. Nevertheless, the results in this thesis allowed the author to develop an analysis framework that can be replicated elsewhere (voltage regulation analysis and OPF-based reactive power pricing).

The proposal of rate design will be made in terms of MW, to use the results analysis of the study. From the different rate designs used and studied on other states, we recommend modifying some models for the case of Puerto Rico. The Full Value Tariff from New York, the division by sized-based for the residential charge would be an effective way to divide the rates for residential and small commercial customers. It is similar to the tiers division by demand or DG capacity used in other programs such as Feed-in Tariffs. For the purpose of this study, the divisions are made by different types of feeder depending on demand or DG penetration: less than 1MW; between 1MW and 11 MW; more than 11 MW.

The typical demand charge, which is based on the peak load should be substituted by the proposed network subscription charge of the FVT program. The peak load sometimes is just for an instant or a short time period and with the proposed network subscription charge, what will be charged is the maximum average monthly for residential and small commercial loads. For large commercial loads, it could be maintained as it is, $/kW of subscribed demand.

The new part that would be included are the marginal cost charges. The dynamic pricing is a better way to include all the avoided costs. The ancillary services would be under this component will. Under a new ancillary services structure, the different components of would be separated, because they can be individually charged. This would simplify the way the utility can buy those services from DG. Typically, the ancillary services range of cost is between 0.5 to 1.5 cents/kWh. The marginal costs of this thesis show that the ancillary services like reactive power supply, have a lower cost than the active power supply. The fair value to supply reactive power would be from 1 cents to 10 cents per unit of MVARs-hour.

For the case of voltage regulation, it is more difficult to assign a range to the service because its cost is under the cost of providing active power supply. It is another ancillary service, and considering the benefits provided by this service presented in the simulation results, it could have the same range of cost as reactive power supply. But, this service is linked to the PV active power production, so it can be assumed that it is under the credit the utility gives to the PV owner. In other words, the utility is already paying for the voltage regulation PV-DG gives to the grid in the credit the utility gives to the PV owners. In case that this service needs to be separated as proposed for the reactive power, the credit given to the PV owner must be decreased, but a fair compensation needs to be assigned to the DG voltage regulation service. With these adjustments in the credit for own generation, and price assigned to services PV-DG can bring to the grid, a more balanced structure can be achieved to account for costs and services from both the grid and the DGs.

5. CONCLUSIONS, RECOMMENDATIONS AND FUTURE WORK

Conclusions

Renewable energy has revolutionized the electric power industry. Some states are leading the nation in the integration of distributed generation. In Puerto Rico, new laws have ordered to move to clean energy options, including renewable energy for electric power generation. One of the key challenges of this movement to renewable resources, is the effect on the market and business model of the utility. The net metering program is good as a start to incentive the DG customers, but with the increase of renewable energy use, a new model is necessary. The first objective of this thesis was to estimate the costs of distribution that can be associated to DG customers. A research of what are the distribution costs associated to DG customers was made. Some of these costs are energy, generation capacity, ancillary services, transmission, distribution, environmental, etc. and their costs vary between 0.1 cents per kWh to 7.6 cents per kWh. The second objective was to identify the benefits DG brings to the grid, including power quality benefits. A research of what benefits DG brings to the grid was made. Some of these benefits are the ancillary services: voltage regulation, frequency regulation, reactive power supply, etc. This thesis focused the study on voltage regulation and reactive power supply. Some of the actual electric rate models do not consider the services DG can bring to the grid. The new rate models need to include in their analysis, as a separate category, the ancillary services. These services are becoming more important and more useful to the grid.

The third objective of the thesis was to focus a rate alternatives study on demand levels and energy purchase contracts. This thesis modeled different penetrations of PV DG, concerning active and reactive power on a typical distribution feeder, for different levels of demand during different periods of a day. A proposal for rate alternatives was made depending on DG capacity or demand levels on the feeder: less than 1 MW; between 1 MW and 11 MW; more than 11 MW. The last objective of the thesis was to complete a cost-based analysis of distributed generation in distribution systems. After analyzing the possible penetrations that do not violate voltage limits, an Optimal Power Flow (OPF) method was performed to determine the costs of providing active and reactive power with DG evenly distributed. The typical OPF is performed for transmission networks and the reactive power marginal cost is neglected. On this thesis, an active and reactive distribution OPF was performed. The results of this marginal costs were discussed on Chapter 4, showing representative values obtained (all results for different periods are presented in Appendix C).

The voltage regulation provided by the PV-DG when it delivers real power to the grid is a benefit to the system. It improves the voltage considerably, especially on high demand periods. The results present trends that can be used in other studies to fairly compensate this service. Even though the rooftop PV costs for the OPF were studied, this economic factor is not the only one important to consider. There are other factors to analyze, such as the social, technical and environmental aspects where DG has influence.

The second service analyzed in this thesis was the reactive power supplied by the DG. This is a key contribution of this thesis. As mentioned before, this service is neglected in the economic analysis and studies of transmission and distribution network. The PV DG has the capacity to bring this service to the grid if it is needed, locally or to export to the grid. The cost of reactive power is less than the cost of active power, but this does not mean that reactive power is not important to study. This service also helps to improve the system voltage. As it is produced locally, there are less losses in the system related to the grid supplying reactive power. The costs of producing reactive power by DG means that the utility has to pay to DG owners for the service. One of the advantages of producing it locally is that it gives additional capacity to the grid. Another advantage is, in case of an increase of reactive demand, or decrease in the system voltage, the PV DG can be used to provide those services.

One of the alternatives that the cost analysis brings is that the utility company can modify the net metering credit given to the customer and assign new credits for the services from DG, e.g., reactive power supply. This reactive supply will not be always offered. The DG customers will use PV as an active power generator, but in case that the utility needs locally supplied reactive power, customers would be paid for those services. The cost analysis also shows that the marginal cost of real power supply, with voltage regulation service, decreases as the PV-DG penetration increases.

These values, and others presented in the thesis, are just starting points that require further analysis. A better model, more accurate, for solar PV is needed to yield more accurate cost results. Nevertheless, the results in this thesis allowed the author to develop an analysis framework (voltage regulation analysis and OPF-based reactive power pricing) that can be replicated elsewhere. The proposed alternatives were made varying the demand levels or DG penetrations in the distribution feeder under study.

Recommendations

This thesis is a first step in the studies on ancillary services for Puerto Rico. With the results analysis and the conclusion made, the following recommendations are made:

- For better results, the DG will always be evenly distributed among the feeder. This confirms a conclusion reached in an earlier study, by expanding the analysis to include different levels of solar irradiance and DG penetration.
- The reactive power supply has the effect to increase the voltage level. In this study, it was shown that as the substation voltage decreases after a system event, the DG can provide reactive power to reduce impact on distribution customers.
- On periods with high demand, the penetration of DG could be more.

Future work

This thesis opens avenues to continue the study of the cost and benefits of ancillary services. This study is a first step to analyze the benefits that DG brings to the grid in Puerto Rico, like ancillary services. For this work, there were key assumptions that facilitated the study. For the future, this study could be make with the model of different renewable resources, different demand profiles and different seasonal periods. For the OPF problem, to get more accurate results, a more accurate equation to model the cost function of PV DG and the other generators in the network could be used. Nevertheless, these results can be used as a guide to start the design of new rate tariffs models in Puerto Rico for different customer types. The analysis framework used in this thesis (voltage regulation analysis and OPF-based reactive power pricing) can be used by future researchers to answer important questions such as:

- What is the value of deferring capital improvements to the grid because the DGs are providing these services?

What is the proper value to the grid of the DGs providing these services during emergency or grid congestion conditions?

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APPENDIX A

A.1 Voltage Plots for Case 1- Sunny Day Voltage Regulation

A.1.1 10pm-4am

No DG- [Demand: 3.81 MW]

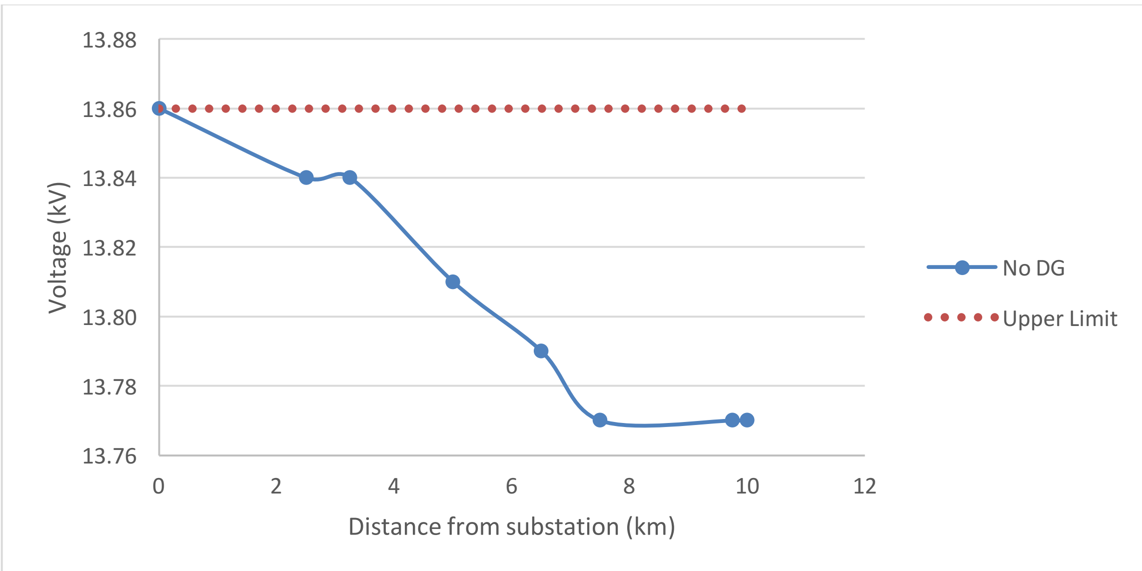

Figure A.1.1.1 Voltage along the feeder with No DG

A.1.2 4am-8am

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

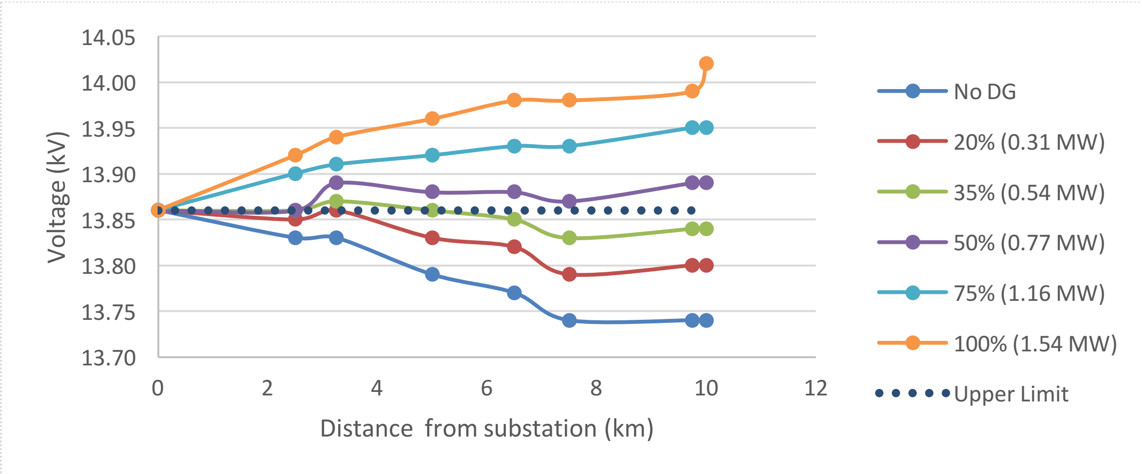

Figure A.1.2.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

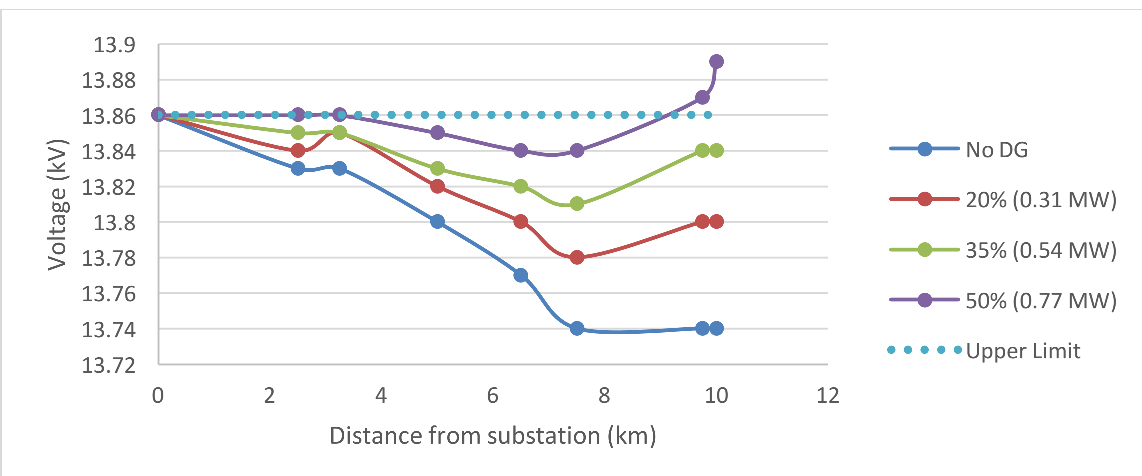

Figure A.1.2.2 Voltage along the feeder with DG at end of feeder

A.1.3 8am-11am

DG output following irradiance curve based on 11 MVA installed capacity - [Demand: 5.66 MW]

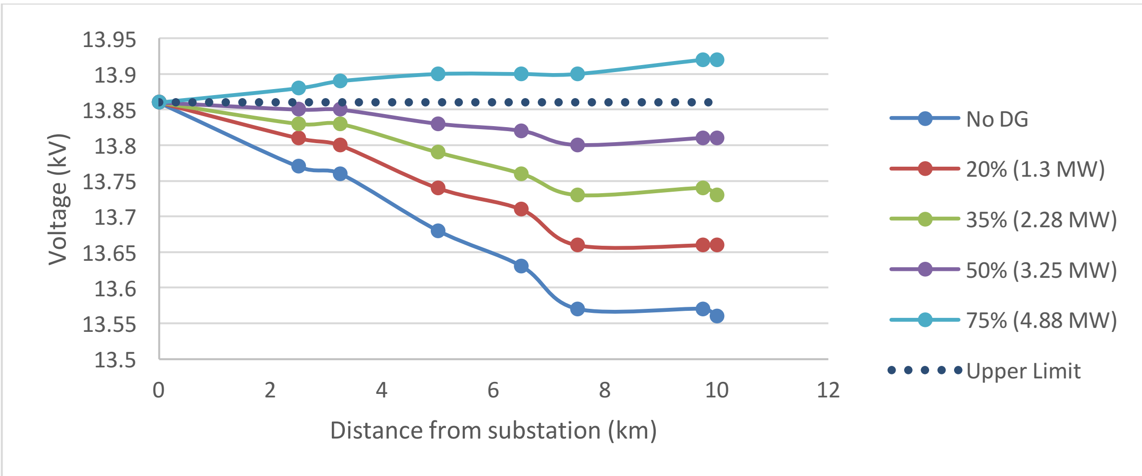

Figure A.1.3.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 5.66 MW]

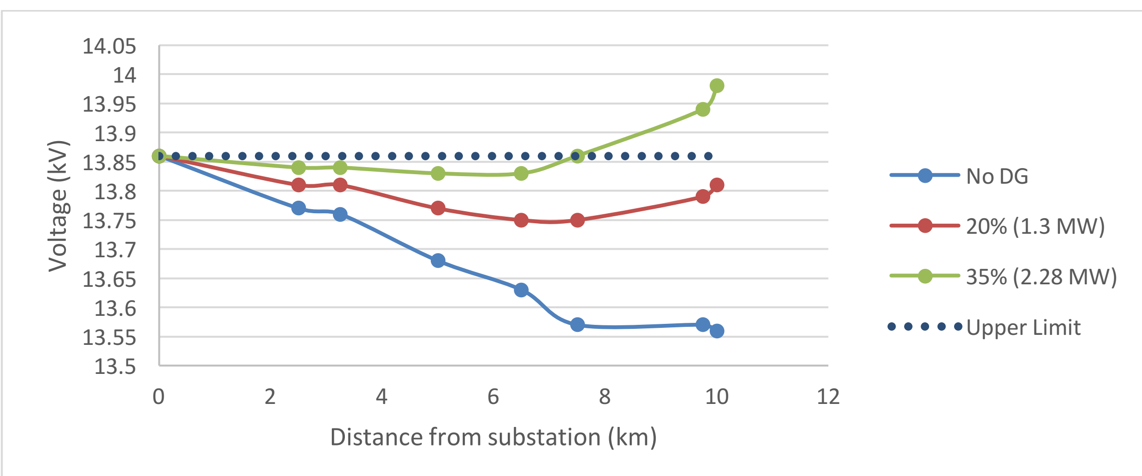

Figure A.1.3.2 Voltage along the feeder with DG at end of feeder

A.1.4 11am-4pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

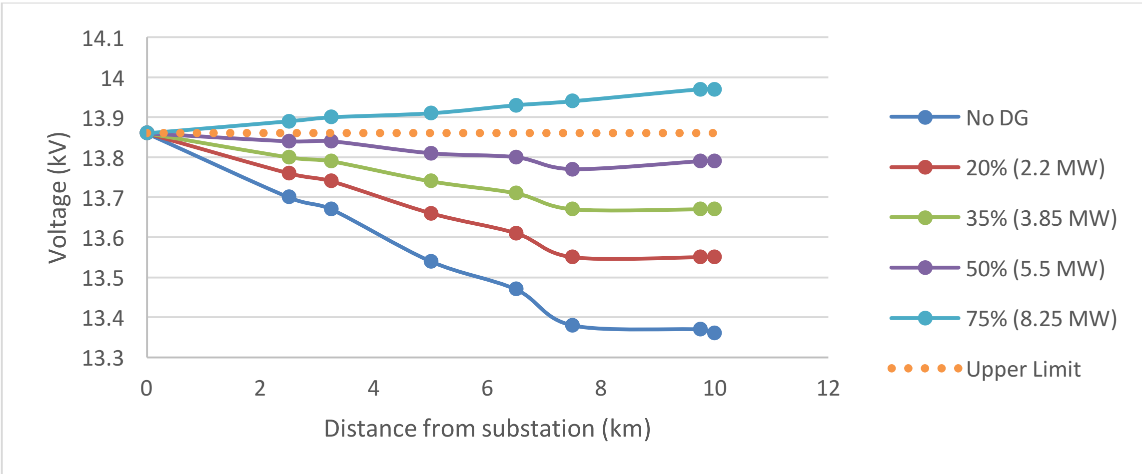

Figure A.1.4.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

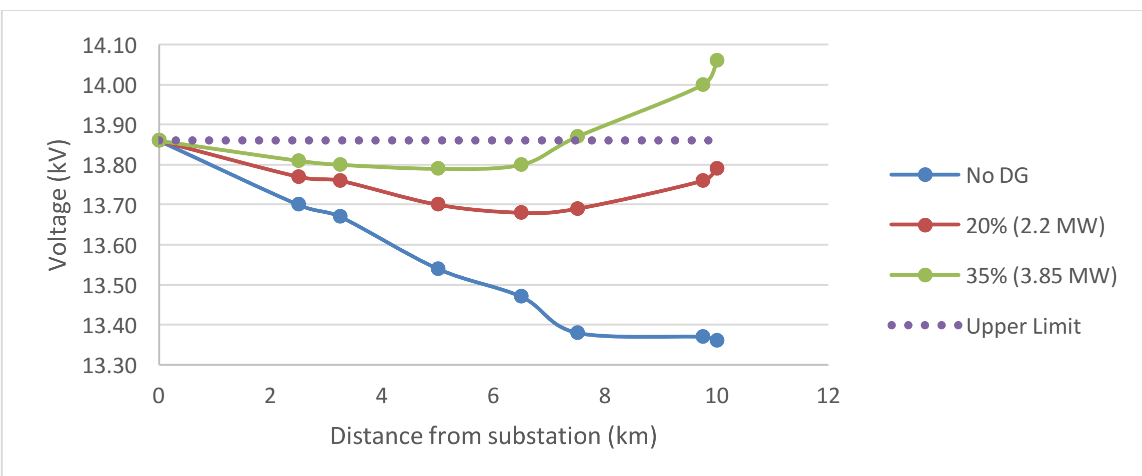

Figure A.1.4.2 Voltage along the feeder with DG at end of feeder

A.1.5 4pm-7pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

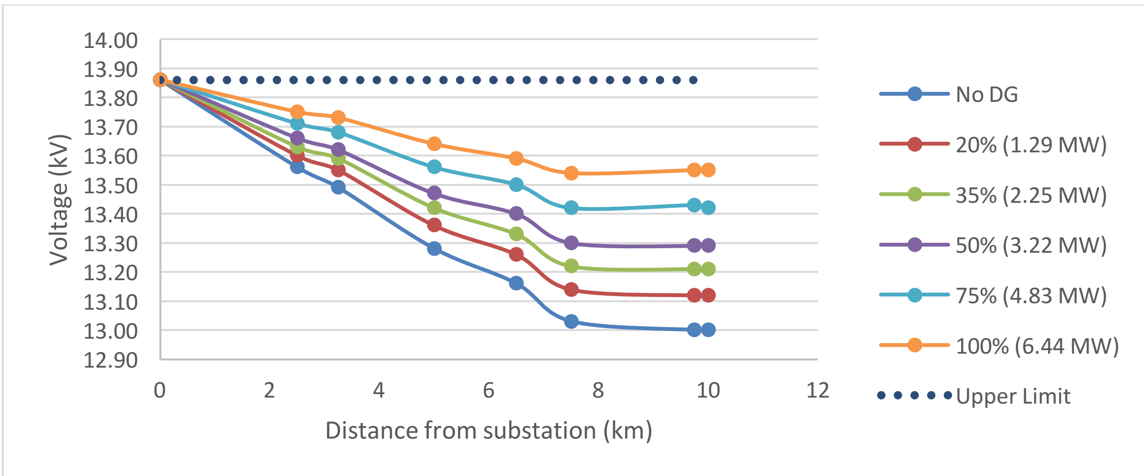

Figure A.1.5.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

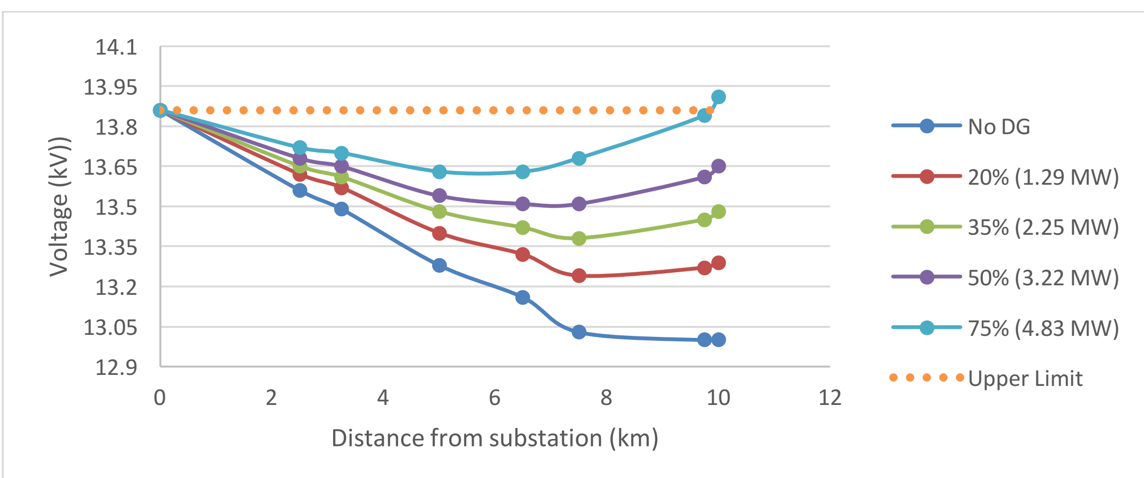

Figure A.1.5.2 Voltage along the feeder with DG at end of feeder

A.1.6 Results for low level insolation (Average PV output: 800 kW)

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.89 MW]

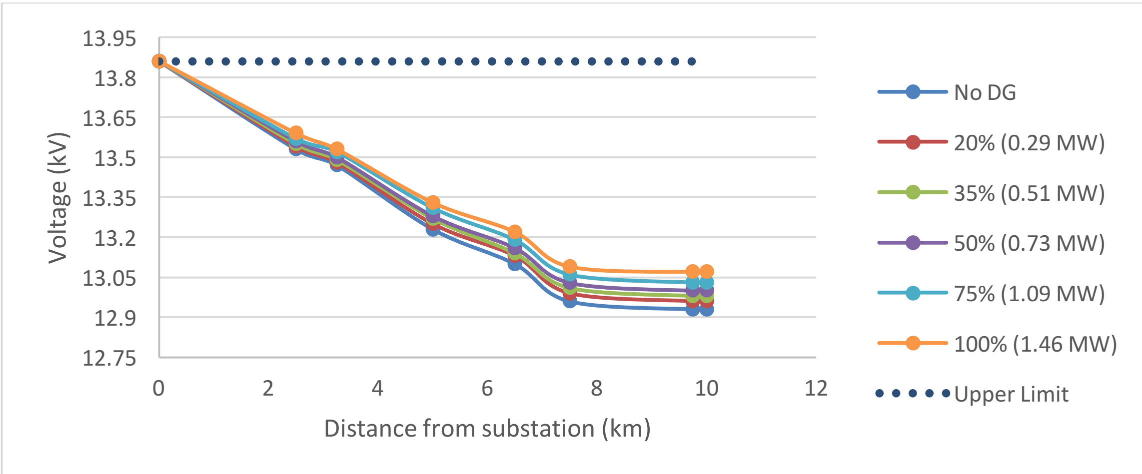

Figure A.1.6.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.89 MW]

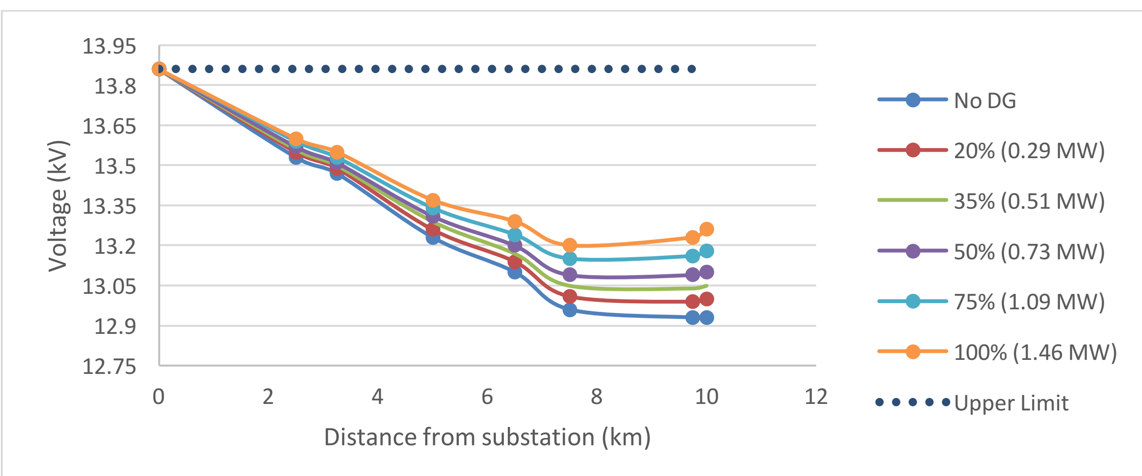

Figure A.1.6.2 Voltage along the feeder with DG at end of feeder

A.2 Voltage Plots for Case 2- Sunny Day with Reactive supply- Voltage 1.05 pu

A.2.1 10pm-4am

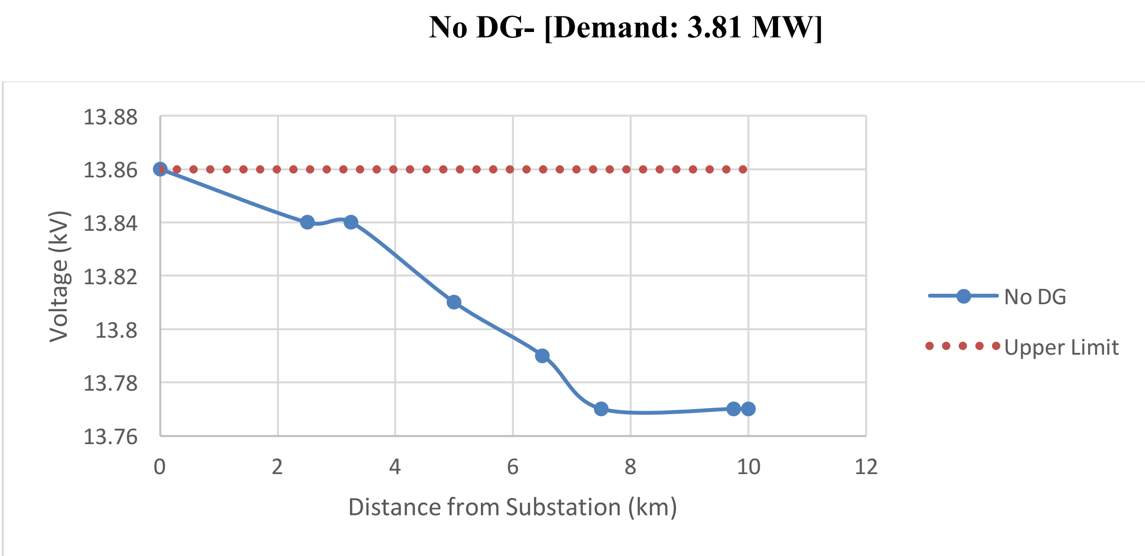

Figure A.2.1 Voltage along the feeder without DG

A.2.2 4am-8am

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

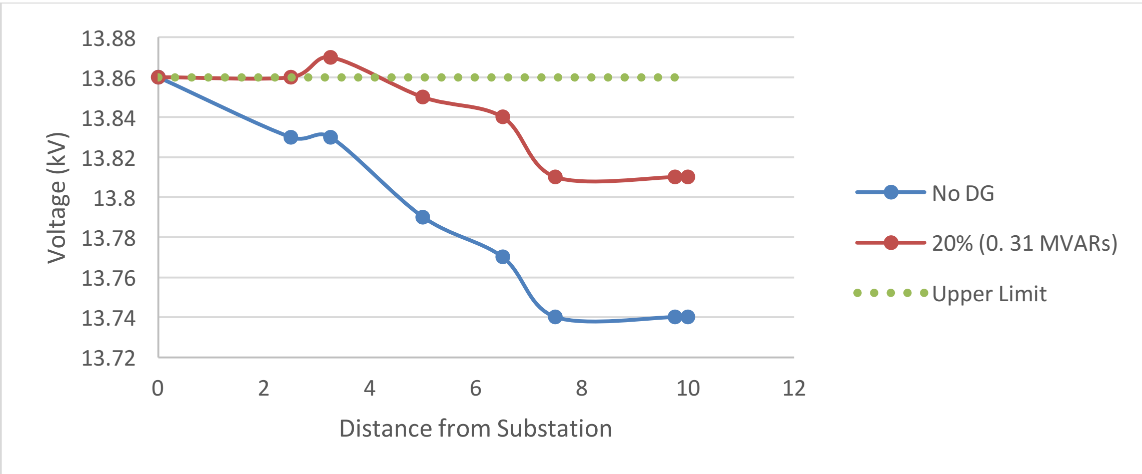

Figure A.2.2.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

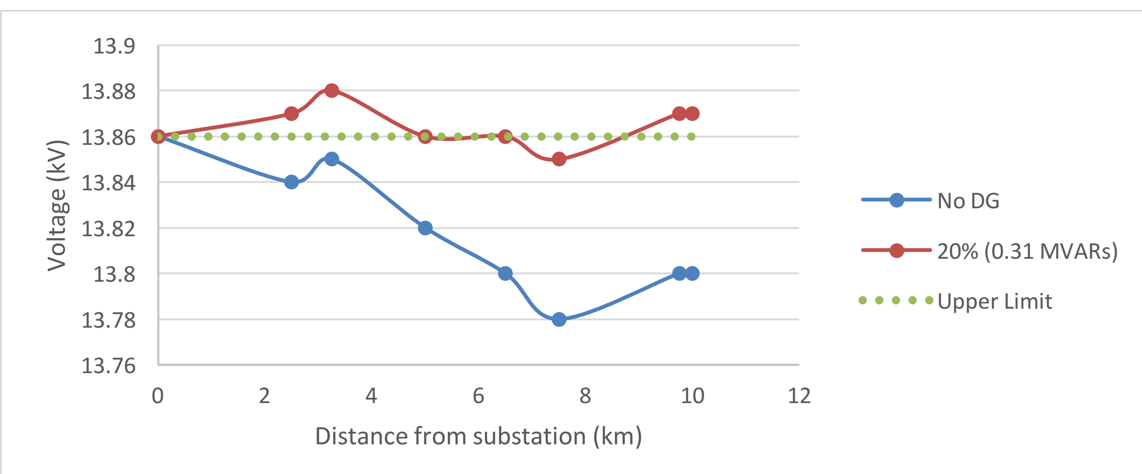

Figure A.2.2.2 Voltage along the feeder with DG at end of feeder

A.2.3 8am-11am

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 5.66 MW]

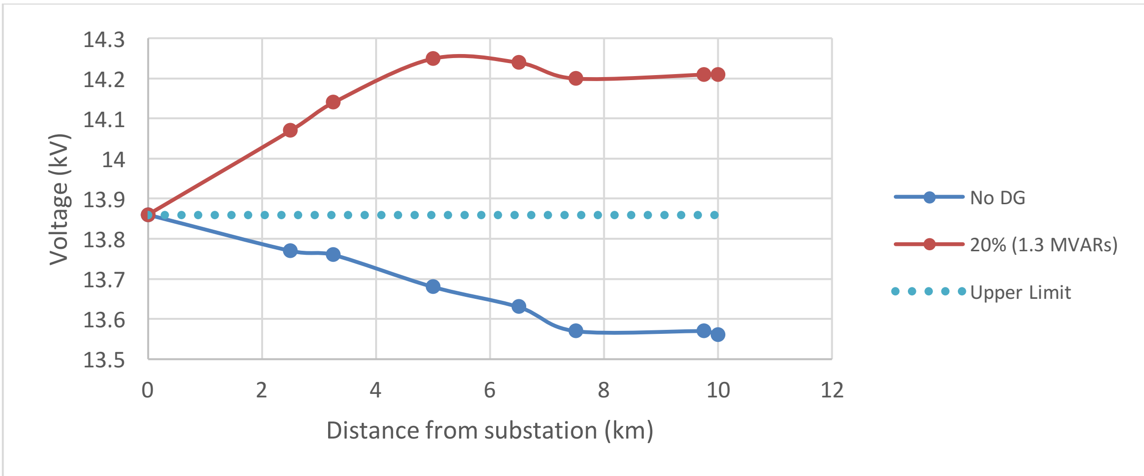

Figure A.2.3.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 5.66 MW]

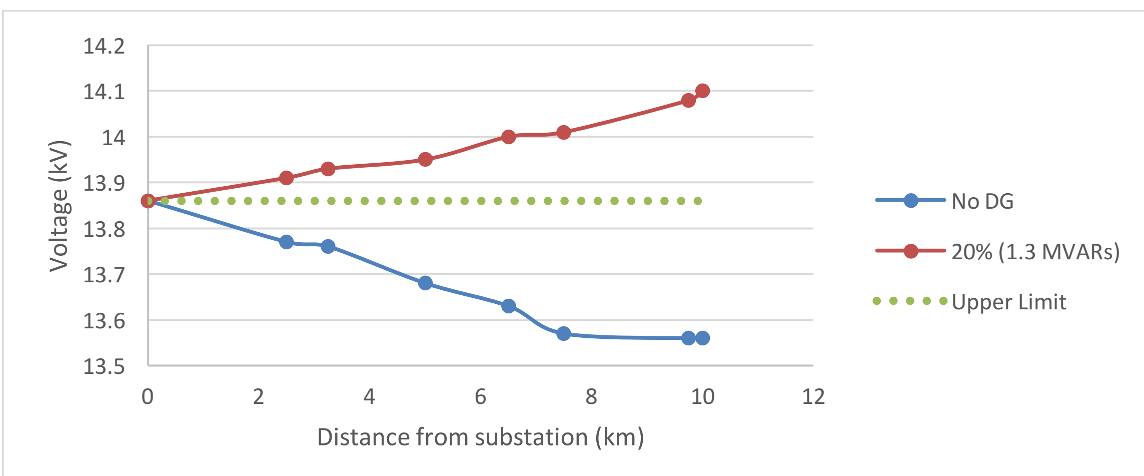

Figure A.2.3.2 Voltage along the feeder with DG at end of feeder

A.2.4 11am-4pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

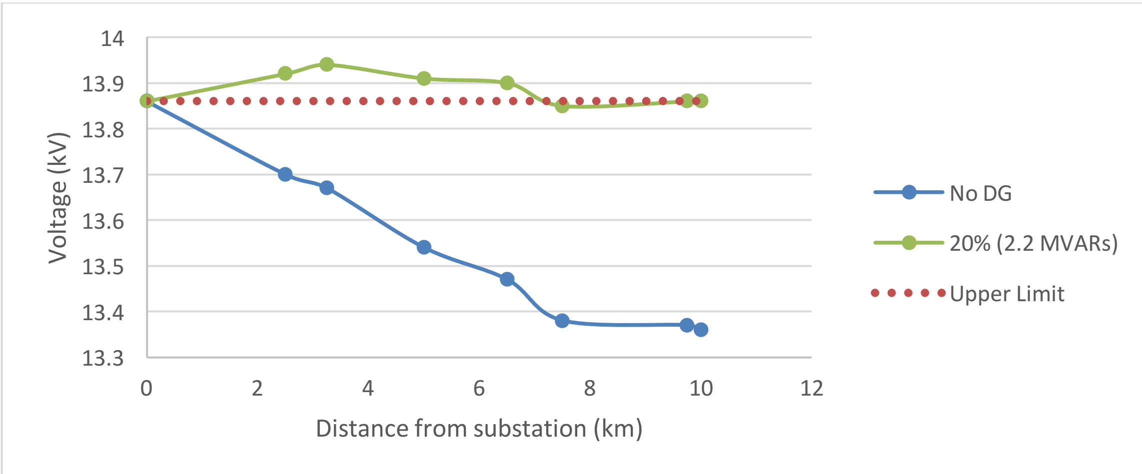

Figure A.2.4.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

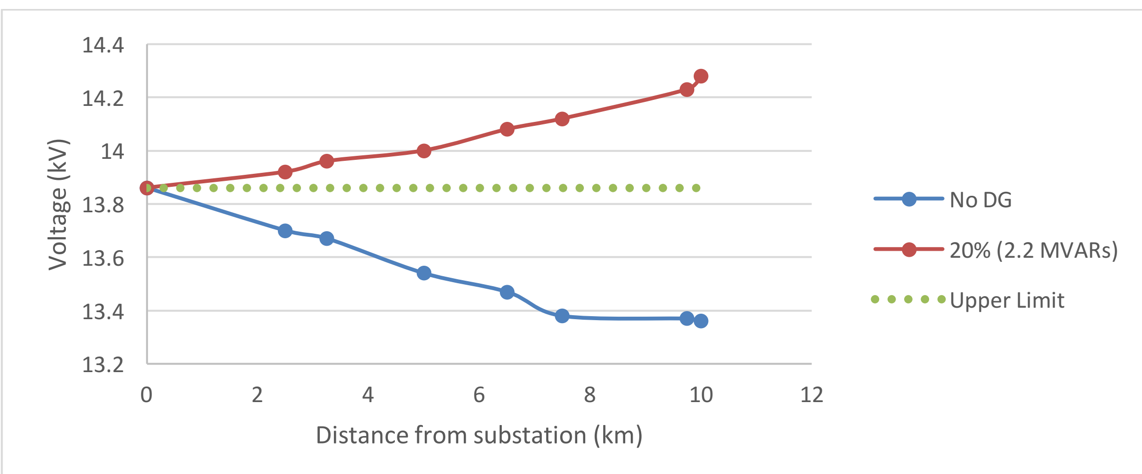

Figure A.2.4.2 Voltage along the feeder with DG at end of feeder

A.2.5 4pm-7pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

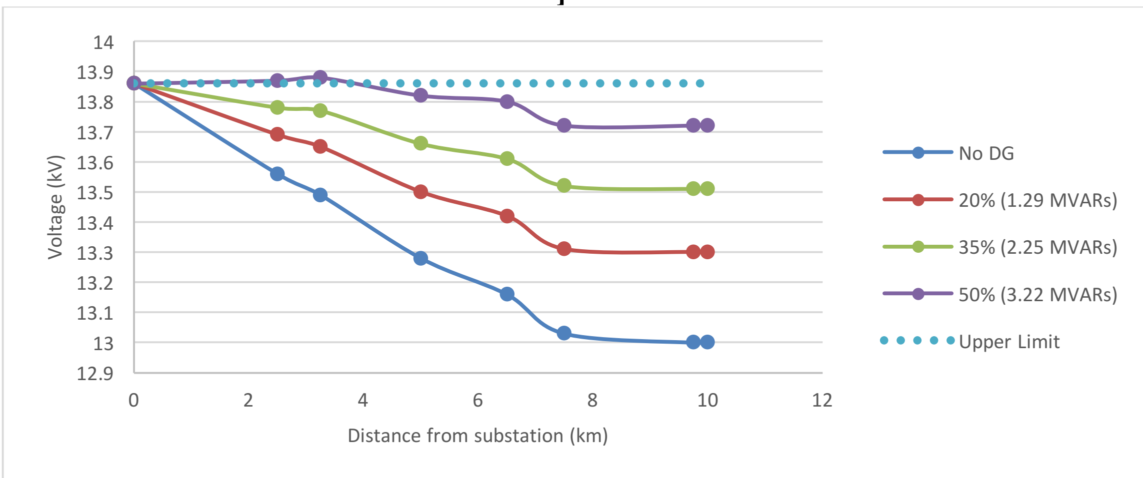

Figure A.2.5.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

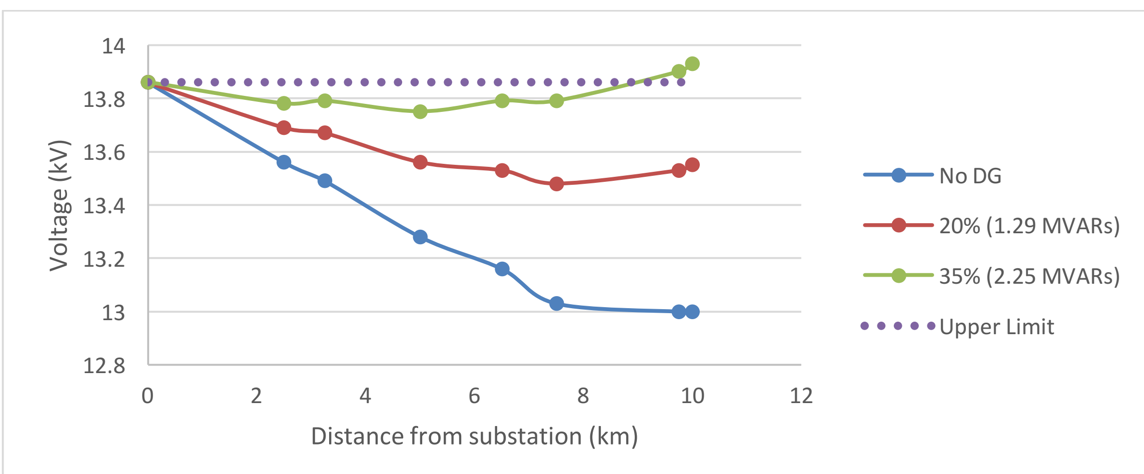

Figure A.2.5.2 Voltage along the feeder with DG at end of feeder

A.2.6 Results for low level insolation (Average PV output: 800 kW)

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.89 MW]

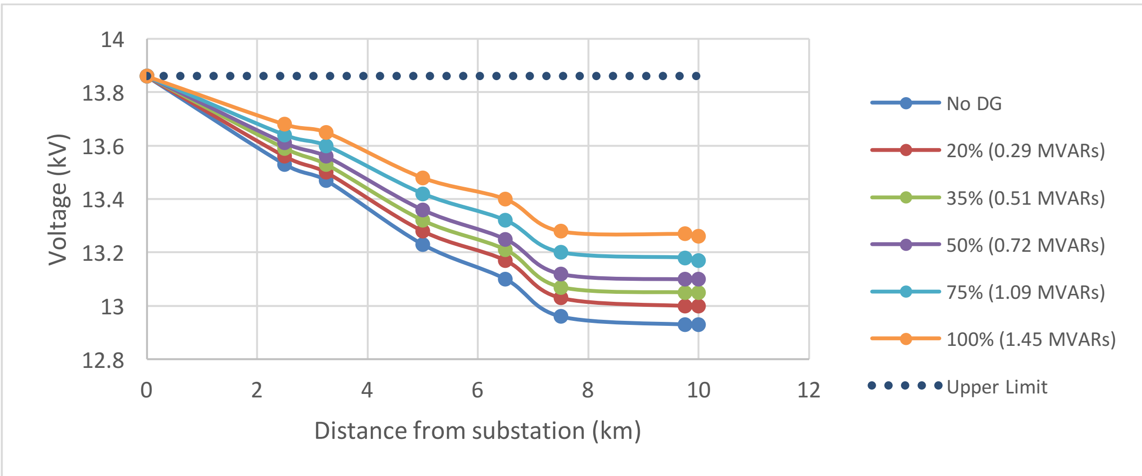

Figure A.2.6.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.89 MW]

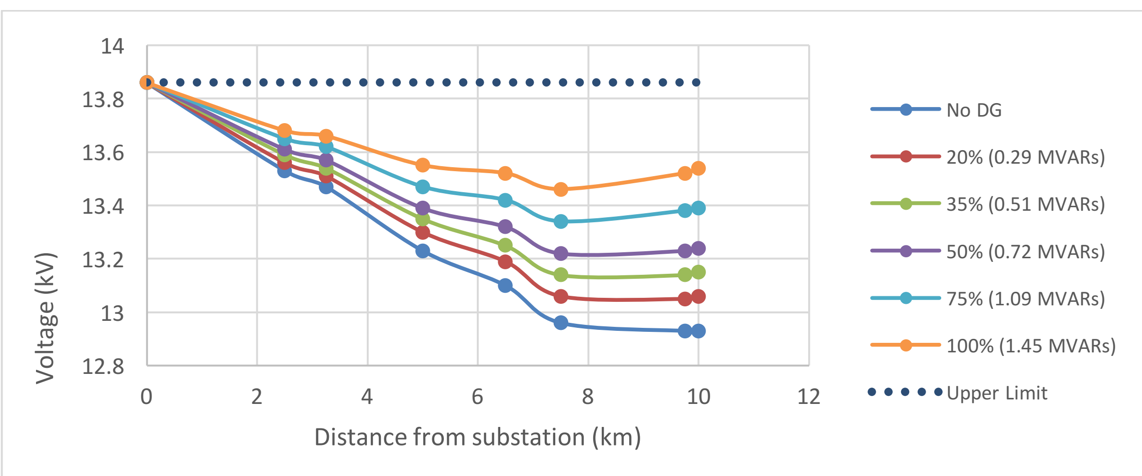

Figure A.2.6.2 Voltage along the feeder with DG at end of feeder

A.3 Voltage Plots for Case 3- Sunny Day Reactive Supply- Voltage 1.00 pu

A.3.1 10pm-4am

No DG- [Demand: 3.81 MW]

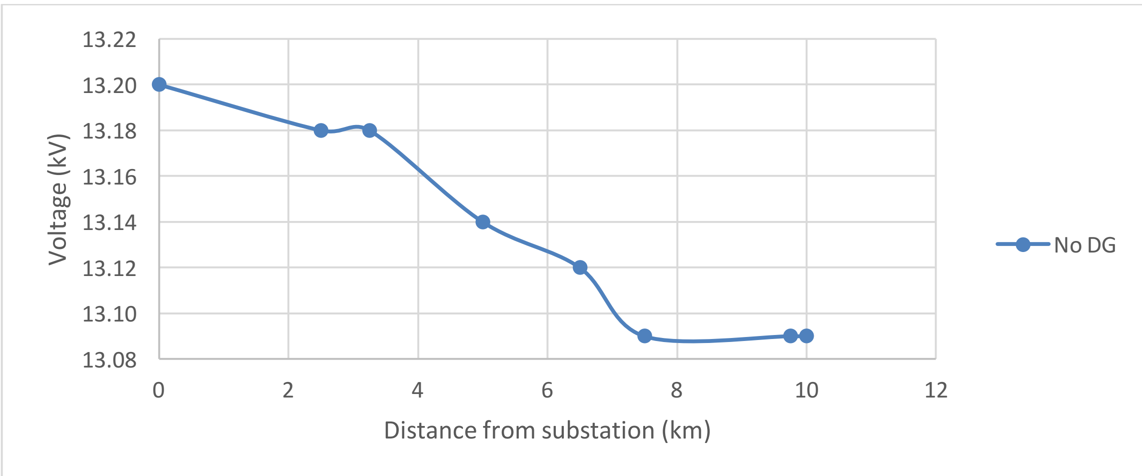

Figure A.3.1 Voltage along the feeder without DG

A.3.2 4am-8am

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

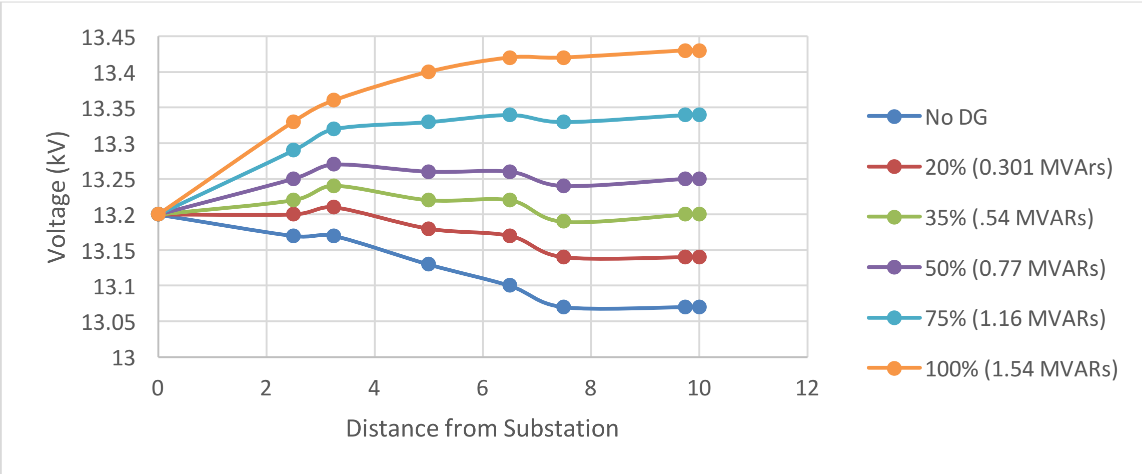

Figure A.3.2.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

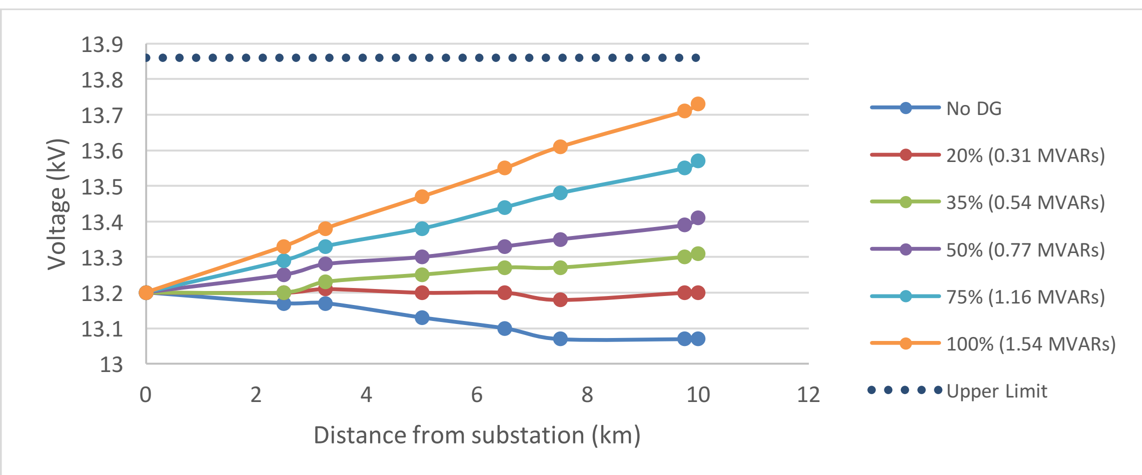

Figure A.3.2.2 Voltage along the feeder with DG at end of feeder

A.3.3 8am-11am

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 5.66 MW]

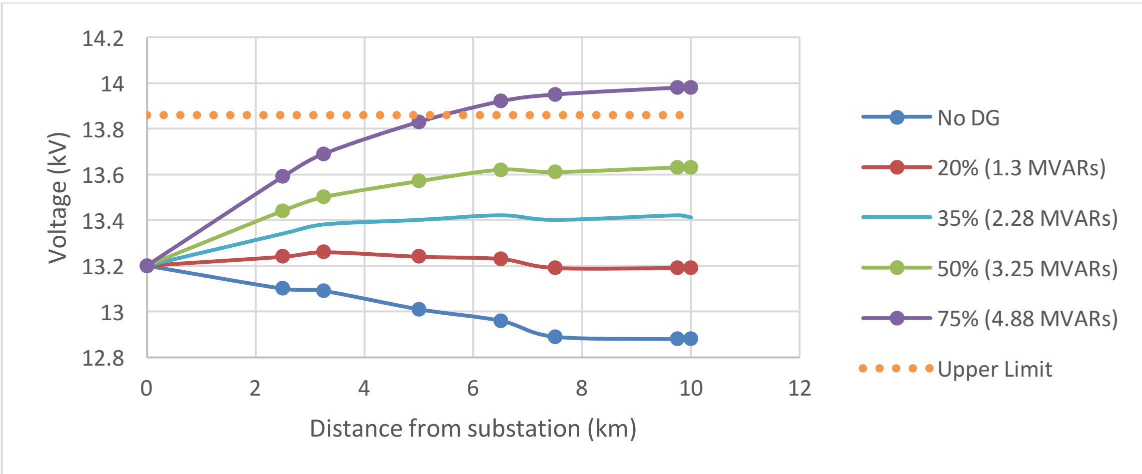

Figure A.3.3.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 5.66 MW]

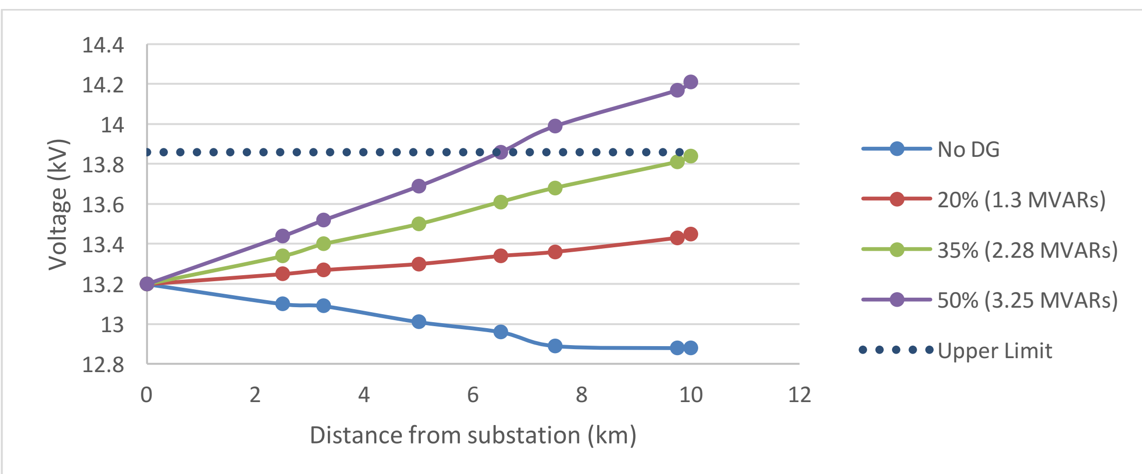

Figure A.3.3.2 Voltage along the feeder with DG at end of feeder

A.3.4 11am-4pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

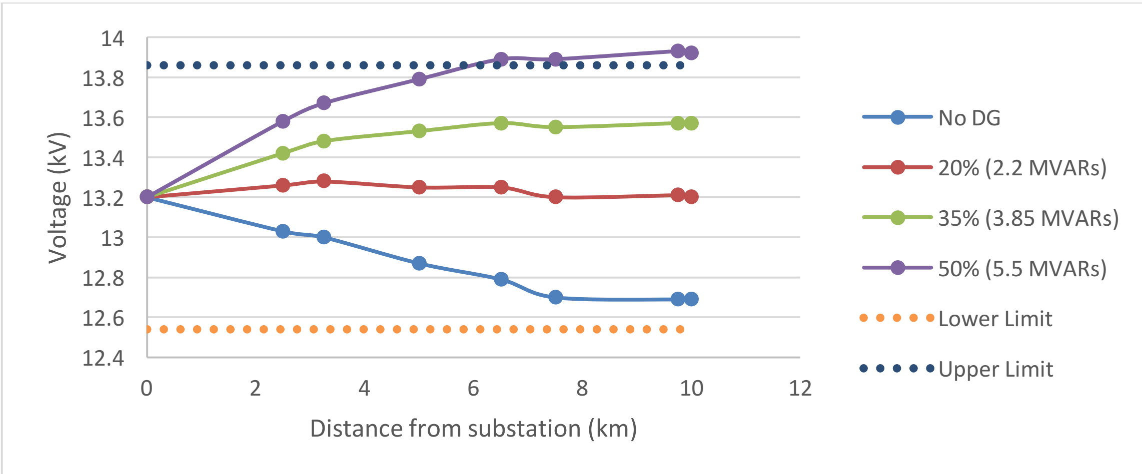

Figure A.3.4.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

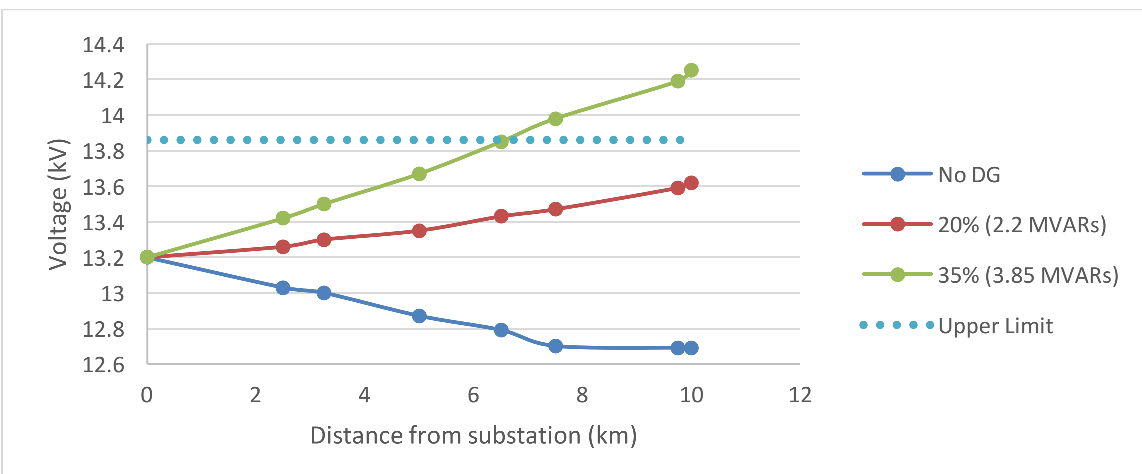

Figure A.3.4.2 Voltage along the feeder with DG at end of feeder

A.3.5 4pm-7pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

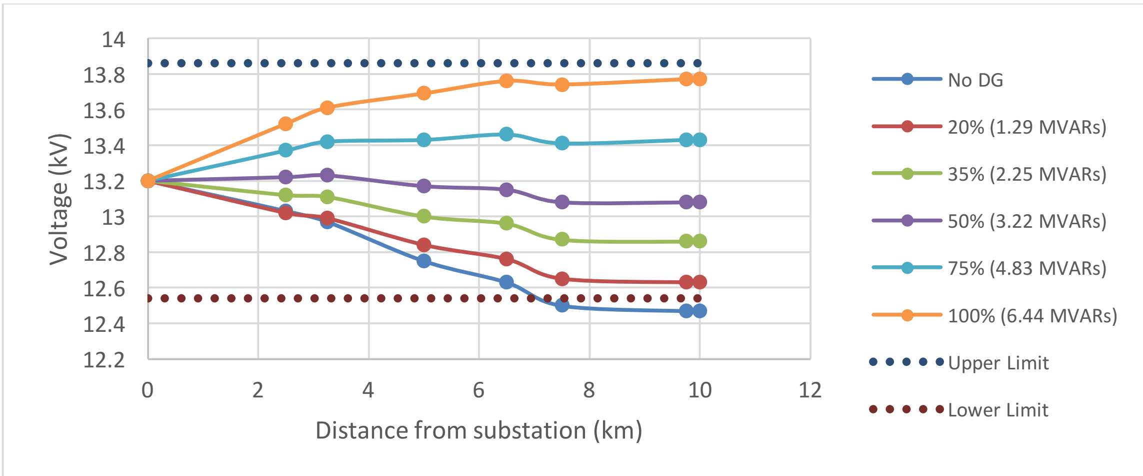

Figure A.3.5.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

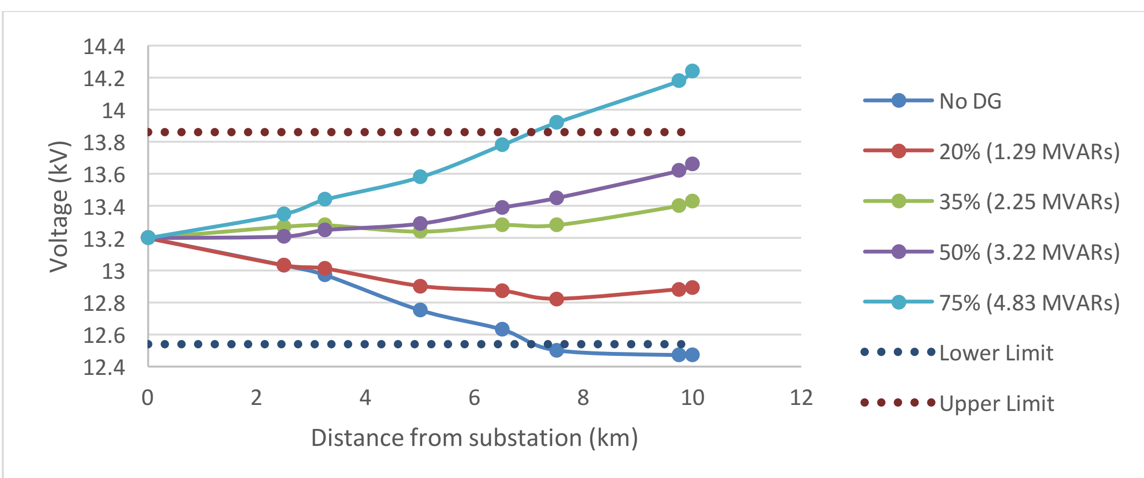

Figure A.3.5.2 Voltage along the feeder with DG at end of feeder

A.3.6 Results for low level insolation (Average PV output: 800 kW)

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.89 MW]

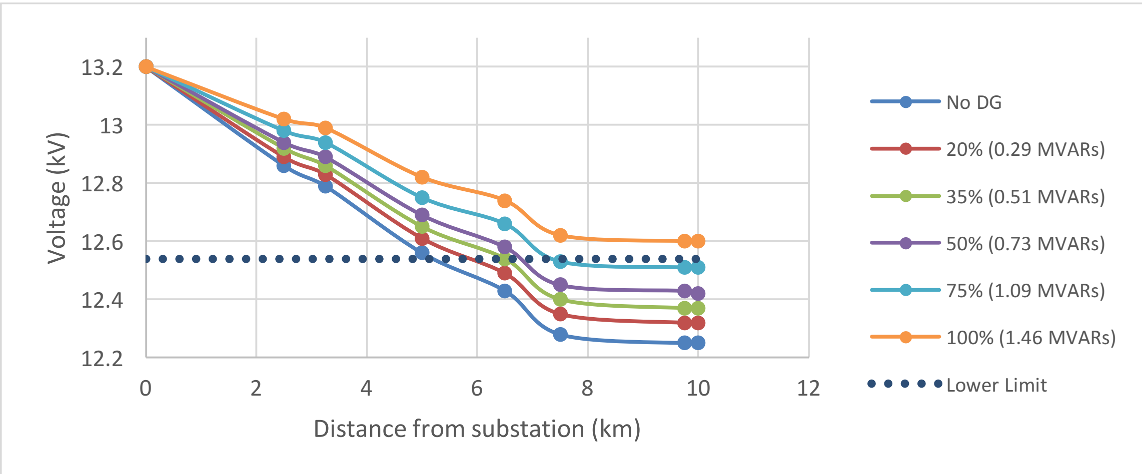

Figure A.3.6.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.89 MW]

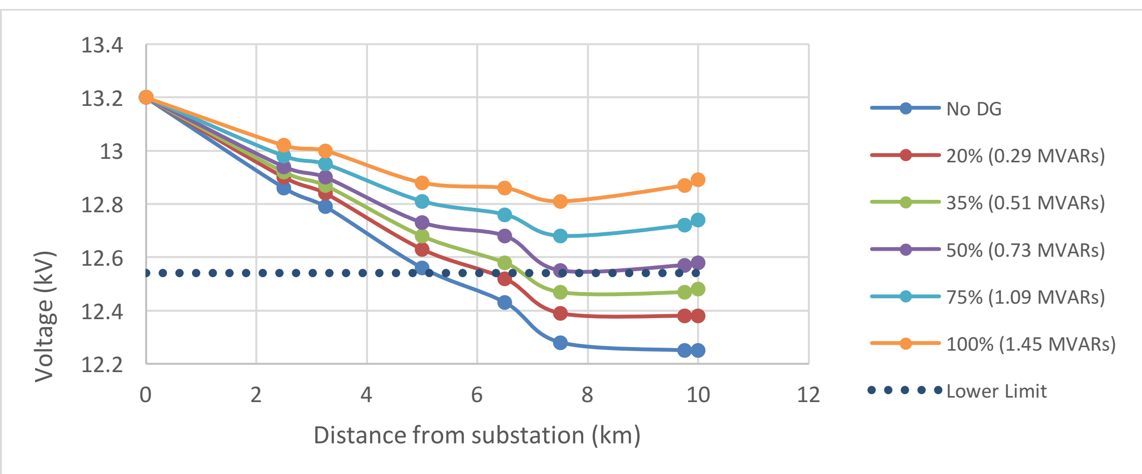

Figure A.3.6.2 Voltage along the feeder with DG at end of feeder

A.4 Voltage Plots for Case 4- Sunny Day Reactive Supply- Voltage 0.95 pu

A.4.1 10pm-4am

No DG- [Demand: 3.81 MW]

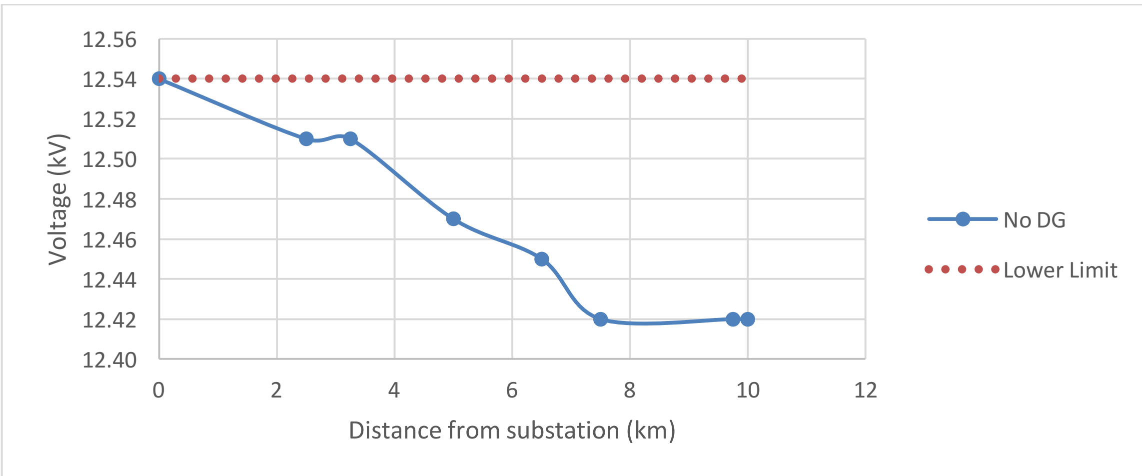

Figure A.4.1 Voltage along the feeder without DG

A.4.2 4am-8am

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

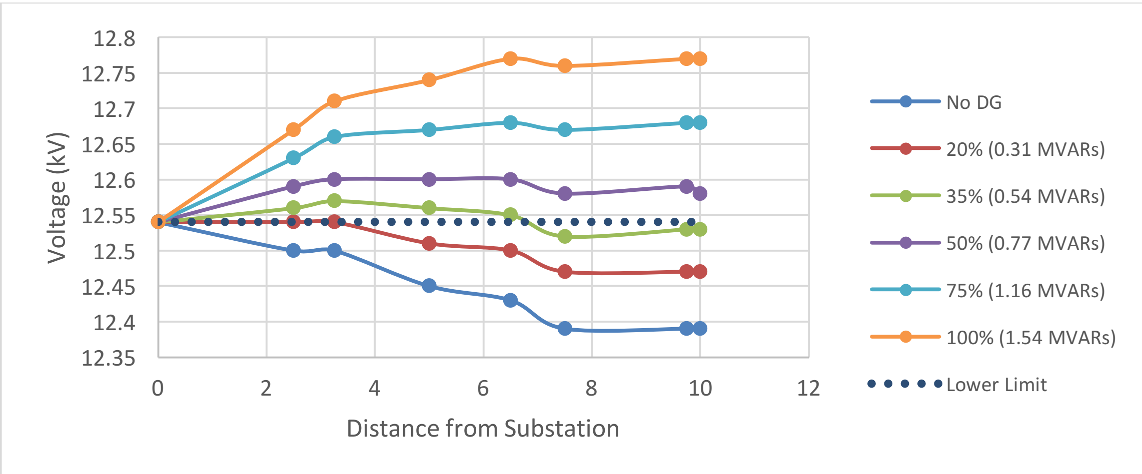

Figure A.4.2.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

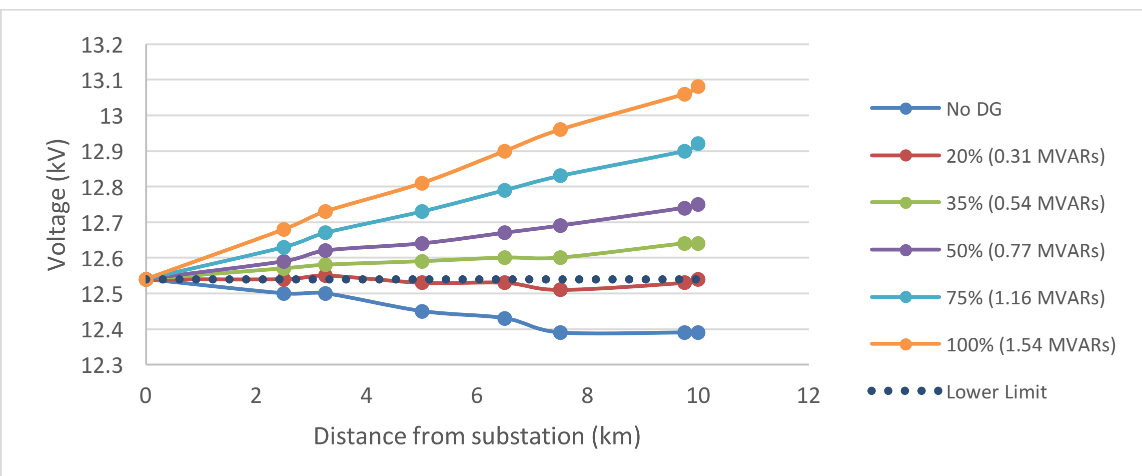

Figure A.4.2.2 Voltage along the feeder with DG at end of feeder

A.4.3 8am-11am

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 5.66 MW]

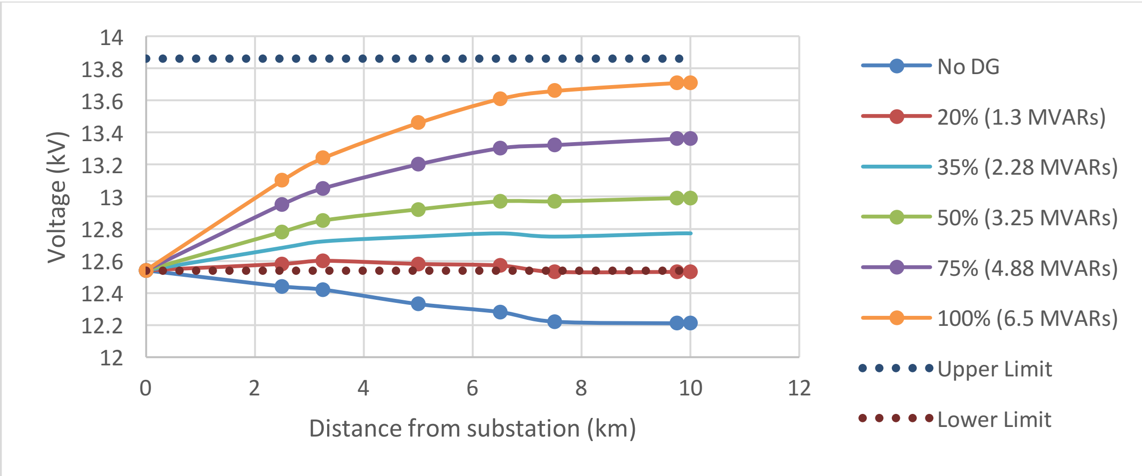

Figure A.4.3.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 5.66 MW]

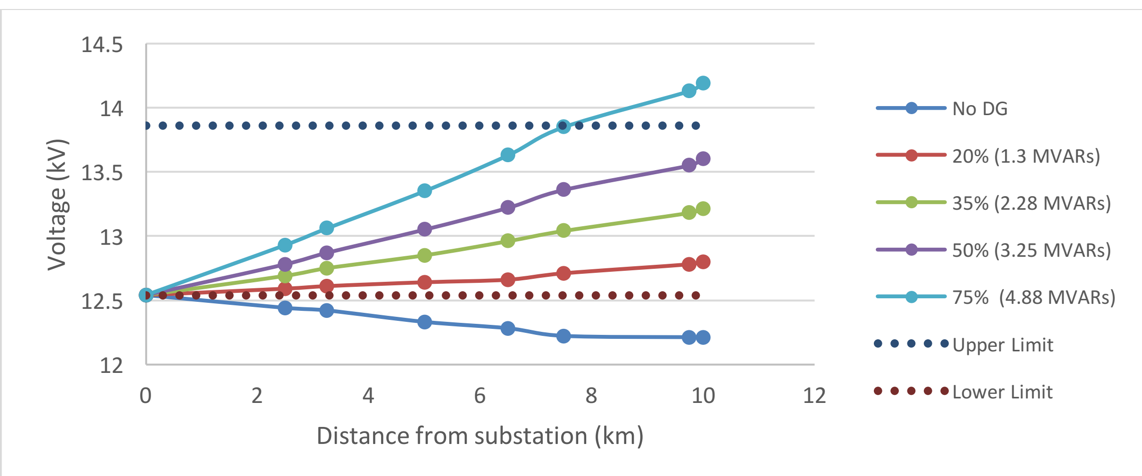

Figure A.4.3.2 Voltage along the feeder with DG at end of feeder

A.4.4 11am-4pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

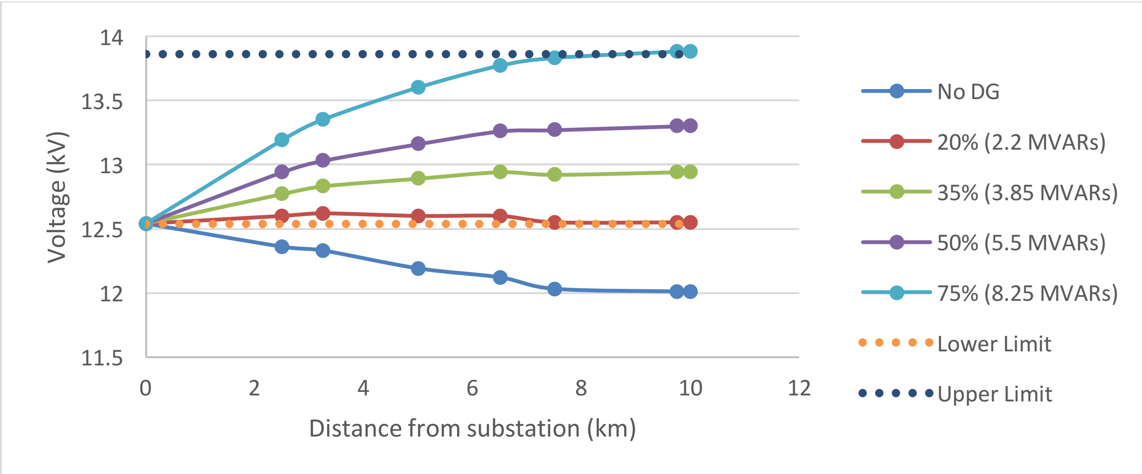

Figure A.4.4.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

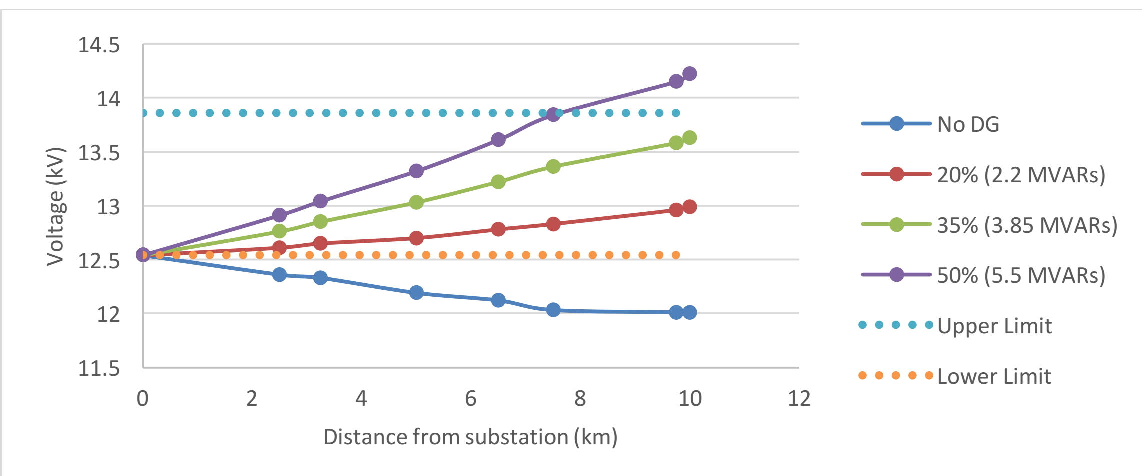

Figure A.4.4.2 Voltage along the feeder with DG evenly distributed

A.4.5 4pm-7pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

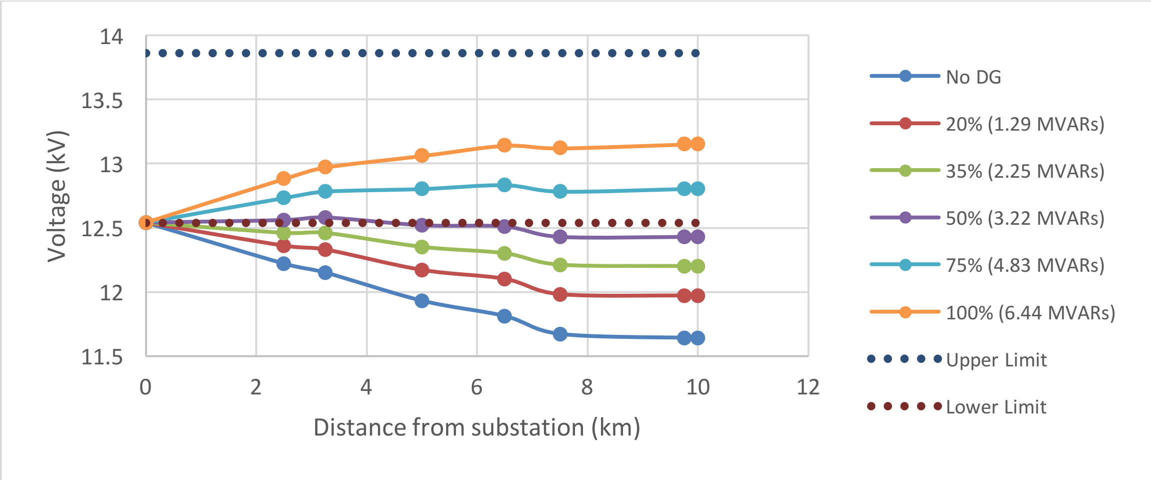

Figure A.4.5.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

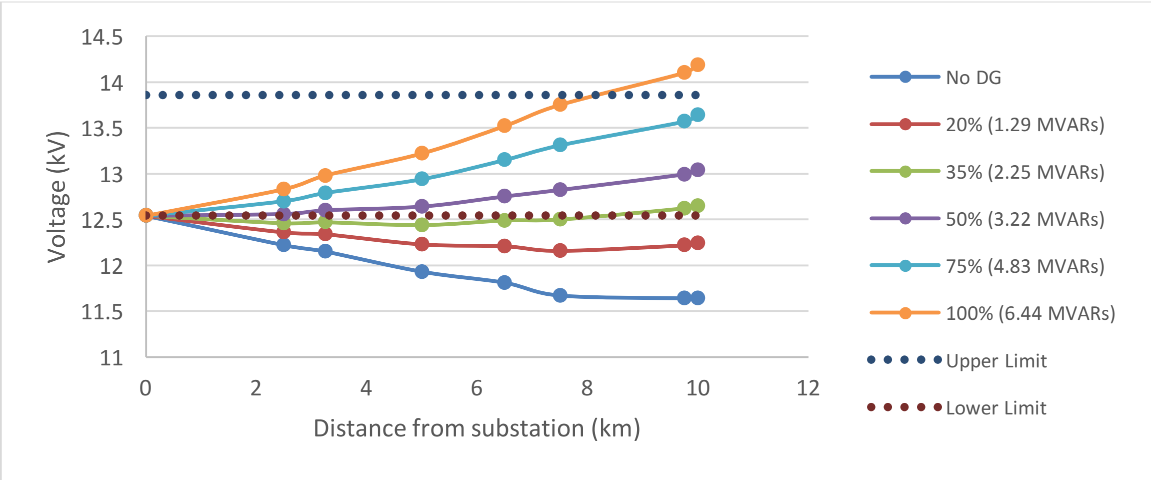

Figure A.4.5.2 Voltage along the feeder with DG at end of feeder

A.4.6 Results for low level insolation (Average PV output: 800 kW)

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.89 MW]

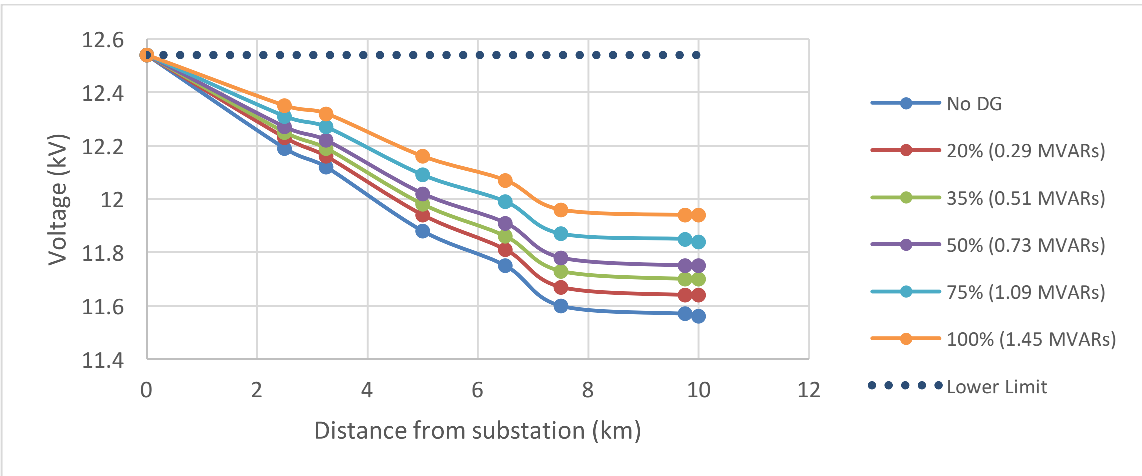

Figure A.4.6.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.89 MW]

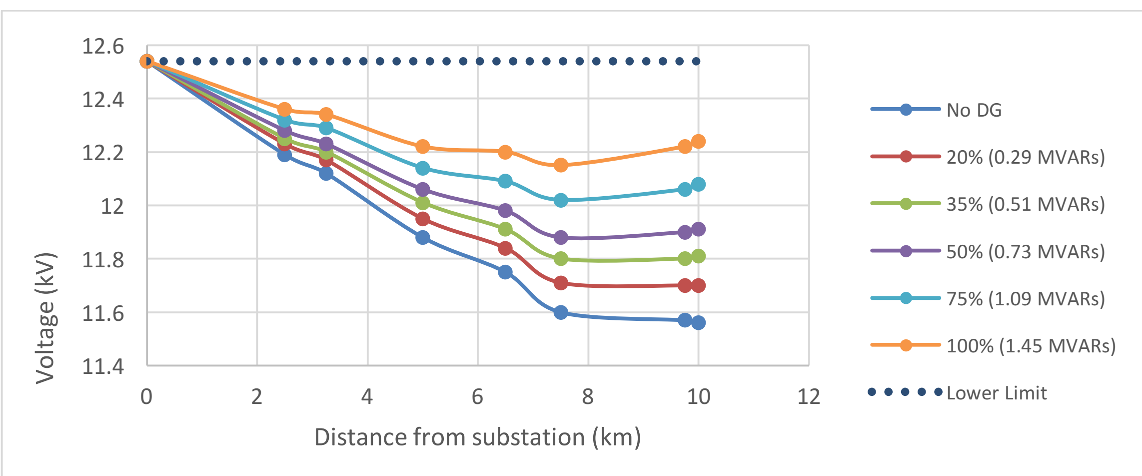

Figure A.4.6.2 Voltage along the feeder with DG at end of feeder

A.5 Voltage Plots for Case 1- Cloudy Day Voltage Regulation

A.5.1 10pm-4am

No DG- [Demand: 3.81 MW]

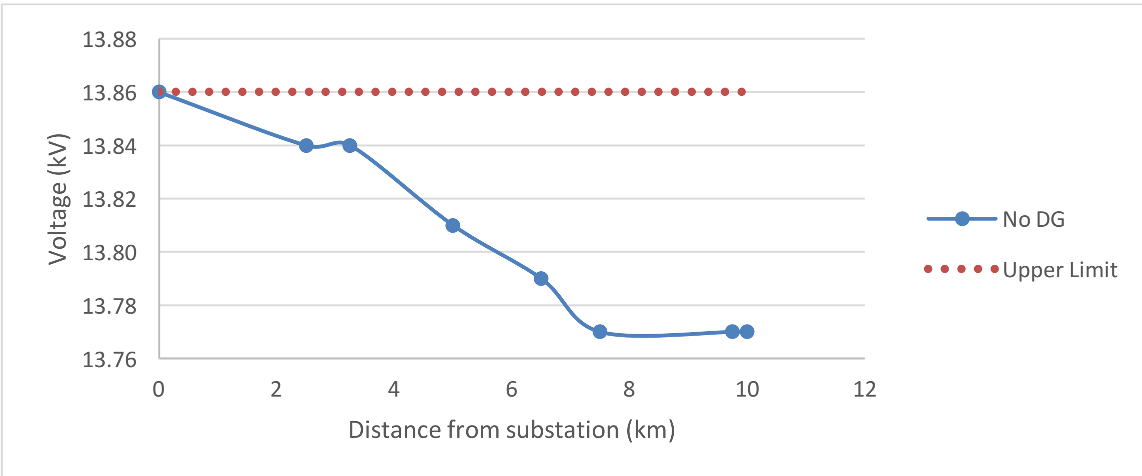

Figure A.5.1.1 Voltage along the feeder with No DG

A.5.2 4am-8am

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

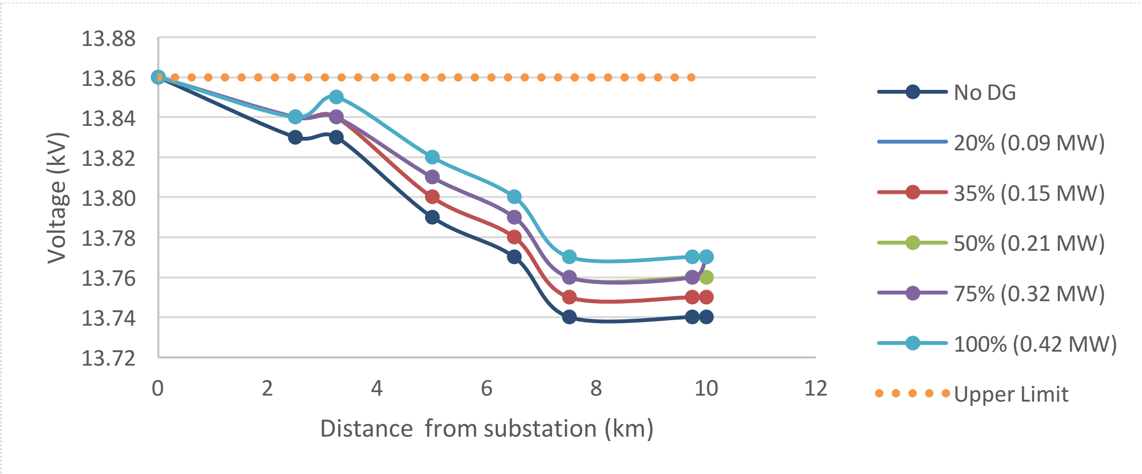

Figure A.5.2.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

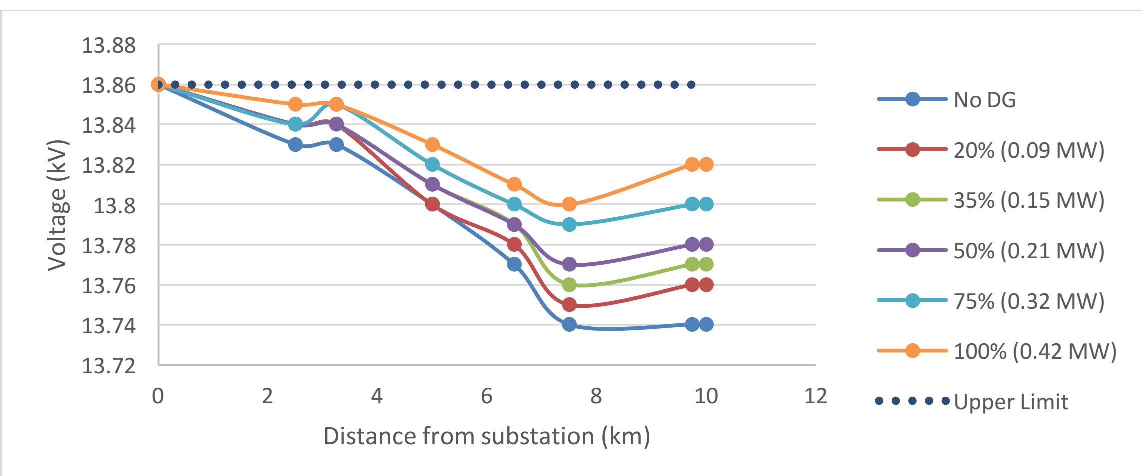

Figure A.5.2.2 Voltage along the feeder with DG at end of feeder

A.5.3 8am-11am

DG output following irradiance curve based on 11 MVA installed capacity - [Demand: 5.66 MW]

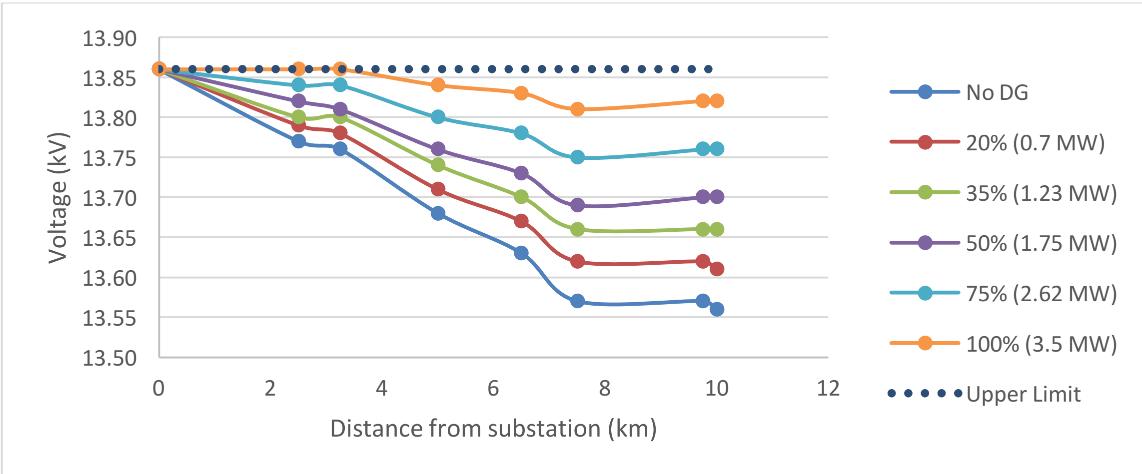

Figure A.5.3.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 5.66 MW]

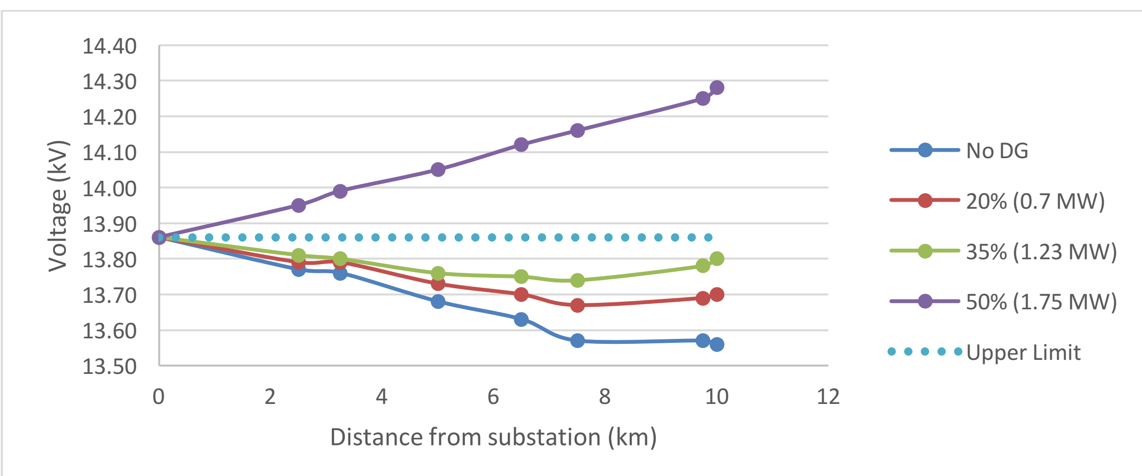

Figure A.5.3.2 Voltage along the feeder with DG at end of feeder

A.5.4 11am-4pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

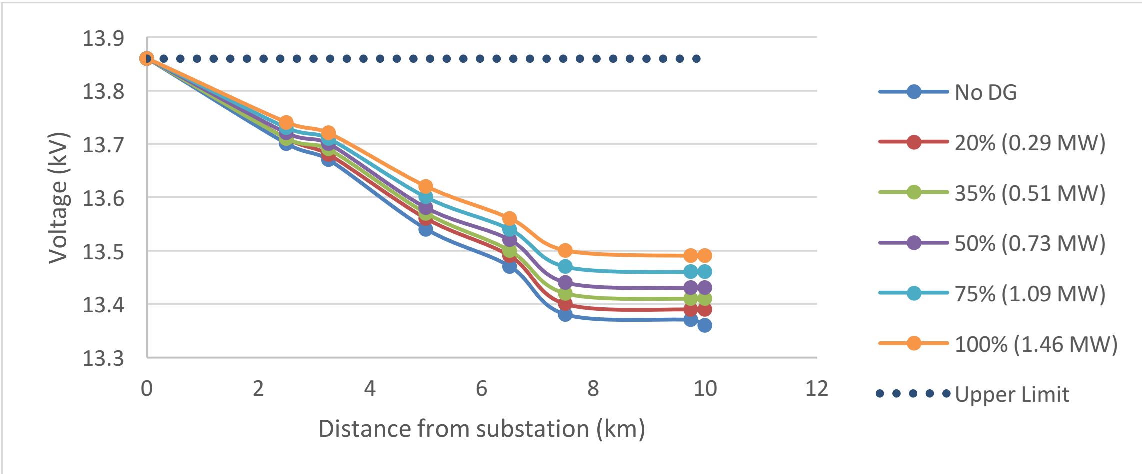

Figure A.5.4.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

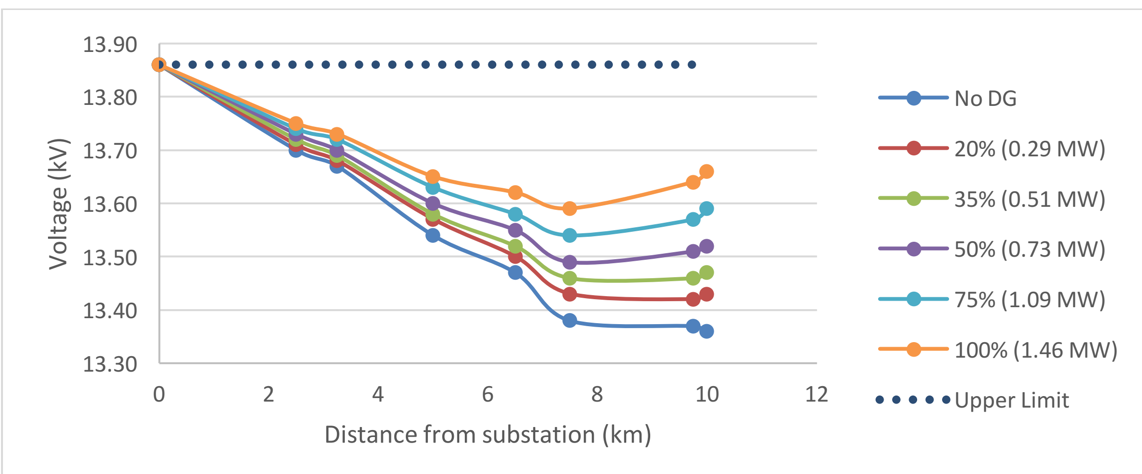

Figure A.5.4.2 Voltage along the feeder with DG at end of feeder

A.5.5 4pm-7pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

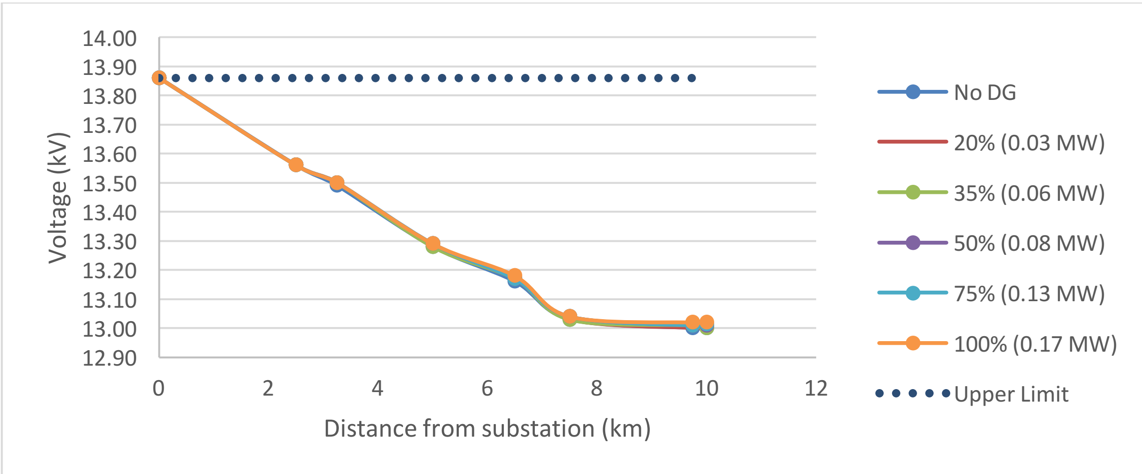

Figure A.5.5.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

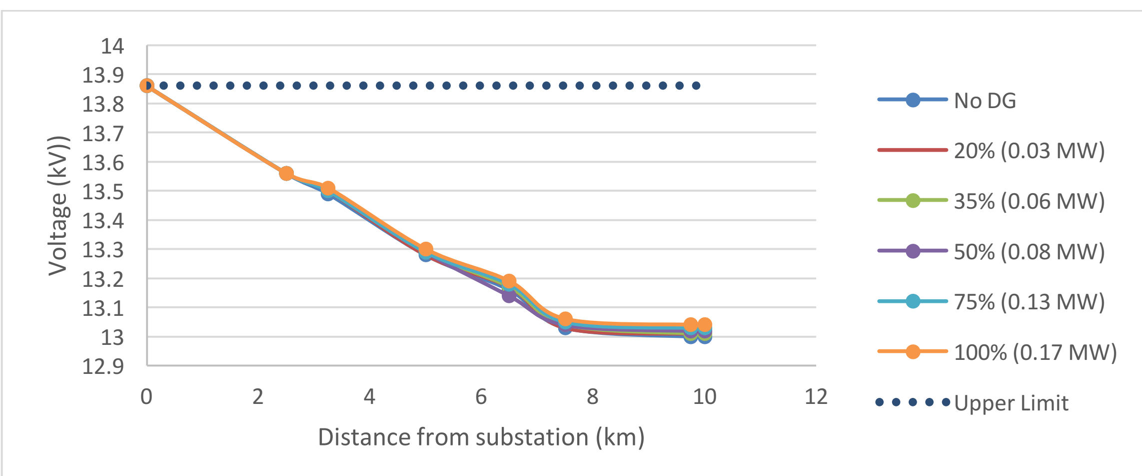

Figure A.5.5.2 Voltage along the feeder with DG at end of feeder

A.6 Voltage Plots for Case 6- Cloudy Day with Reactive supply- Voltage 1.05 pu

A.6.1 10pm-4am

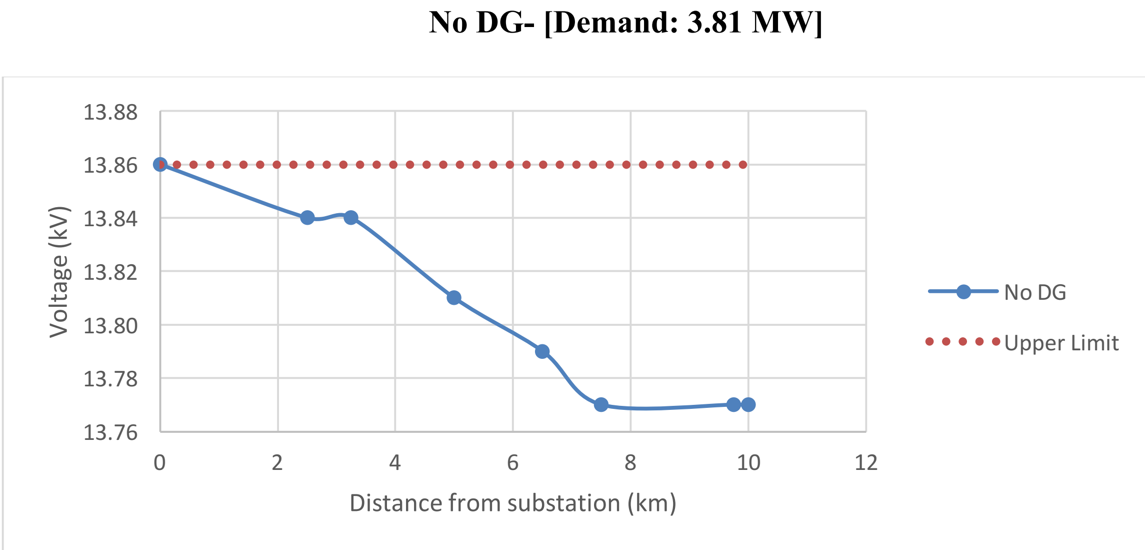

Figure A.6.1 Voltage along the feeder without DG

A.6.2 4am-8am

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

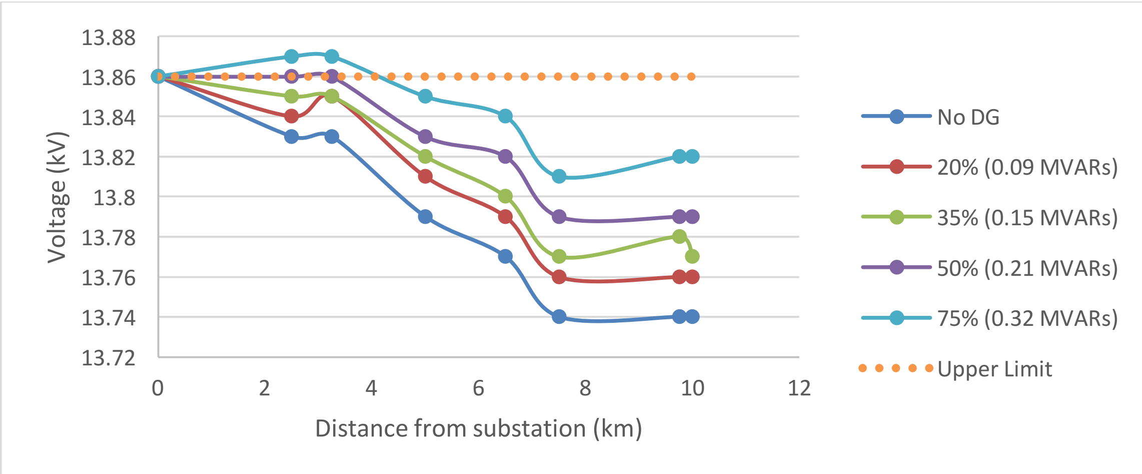

Figure A.6.2.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

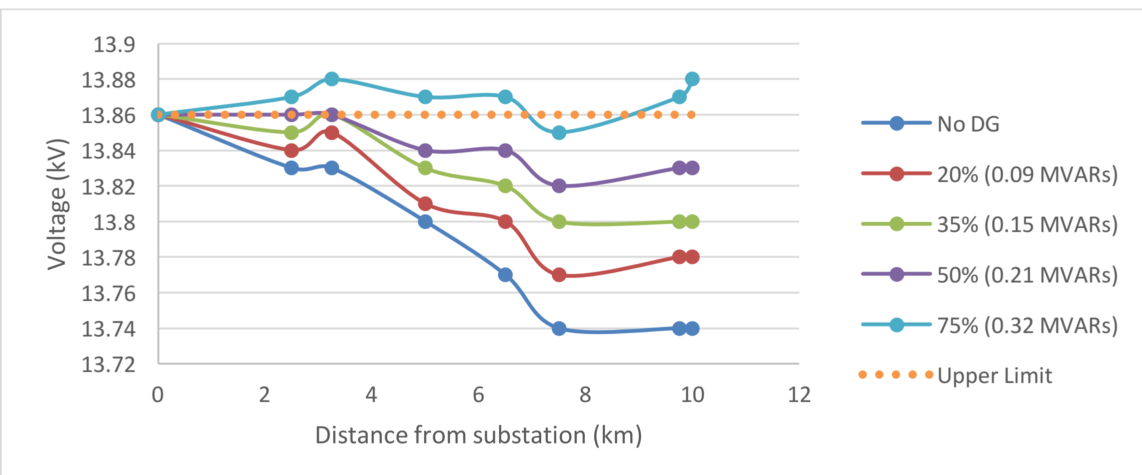

Figure A.6.2.2 Voltage along the feeder with DG at end of feeder

A.6.3 8am-11am

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 5.66 MW]

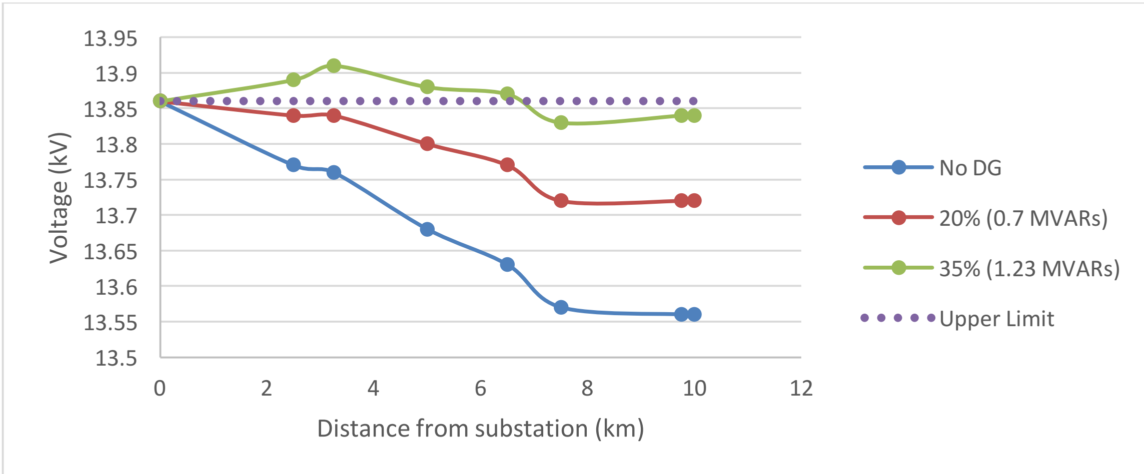

Figure A.6.3.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 5.66 MW]

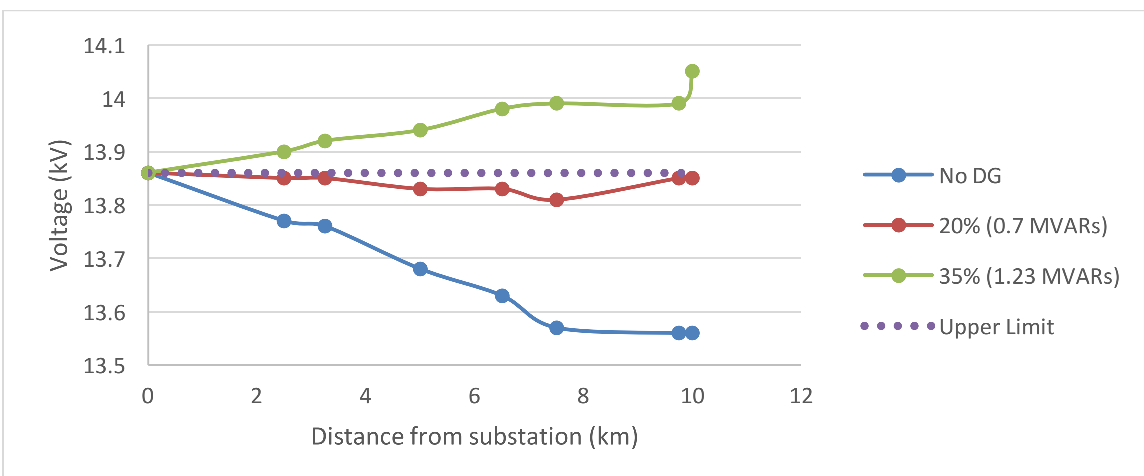

Figure A.6.3.2 Voltage along the feeder with DG at end of feeder

A.6.4 11am-4pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

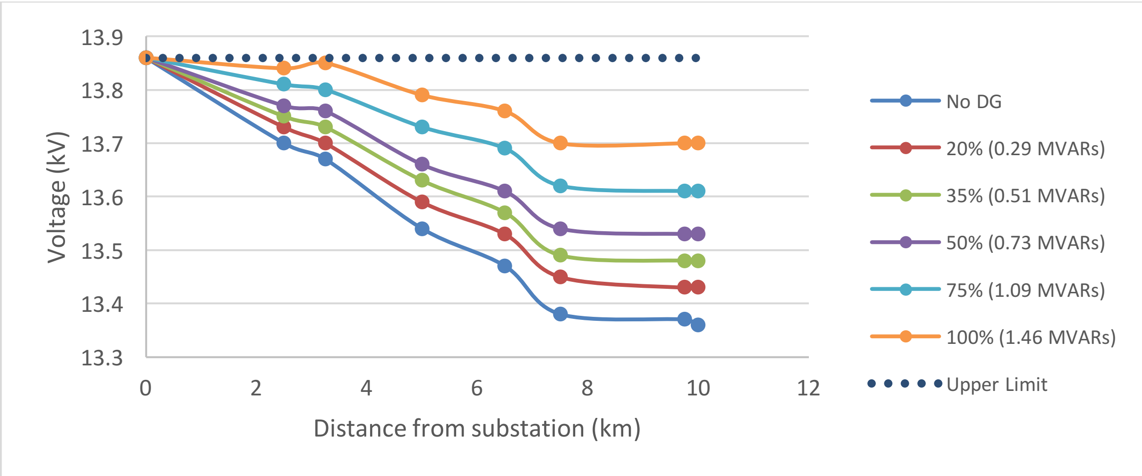

Figure A.6.4.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

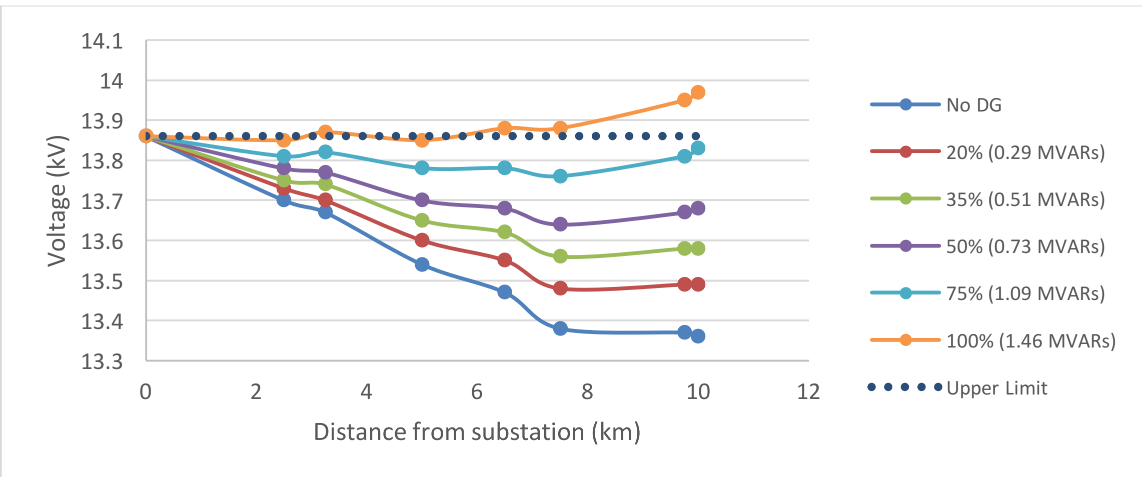

Figure A.6.4.2 Voltage along the feeder with DG at end of feeder

A.6.5 4pm-7pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

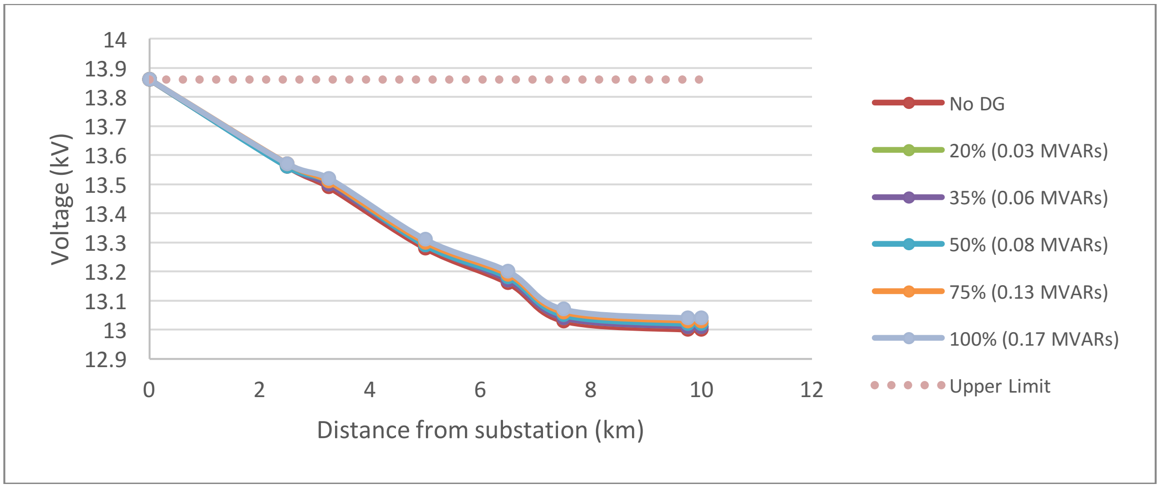

Figure A.6.5.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

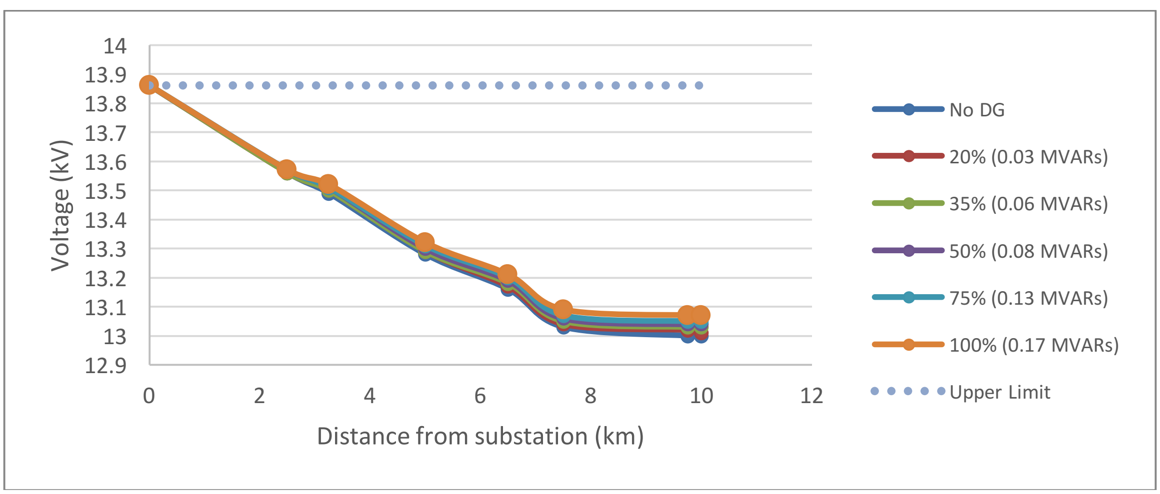

Figure A.6.5.2 Voltage along the feeder with DG at end of feeder

A.7 Voltage Plots for Case 7- Cloudy Day Reactive Supply- Voltage 1.00 pu

A.7.1 10pm-4am

No DG- [Demand: 3.81 MW]

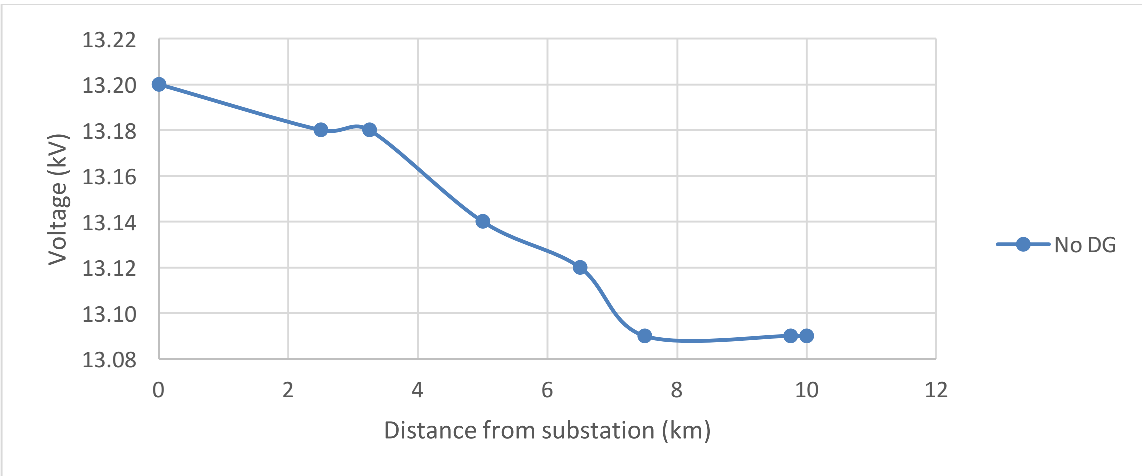

Figure A.7.1 Voltage along the feeder without DG

A.7.2 4am-8am

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

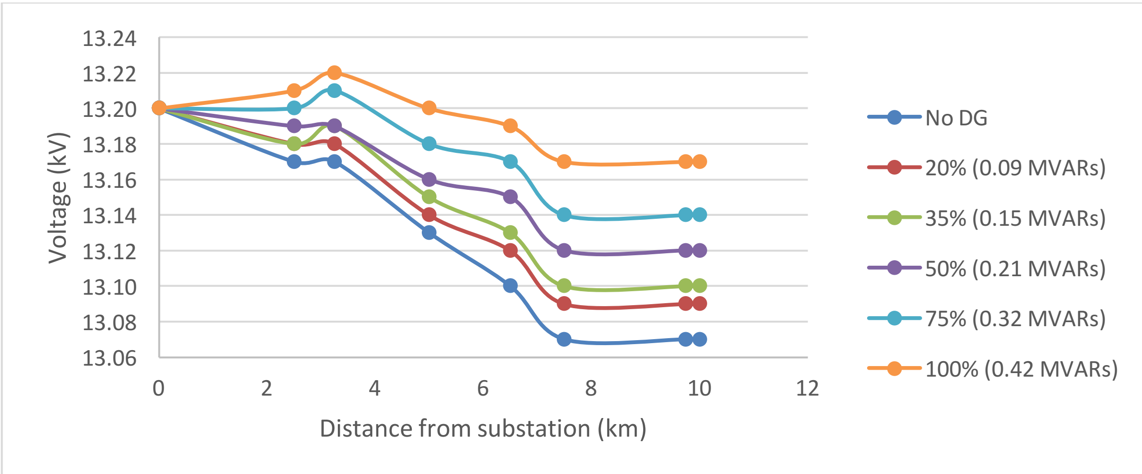

Figure A.7.2.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 4.03 MW]

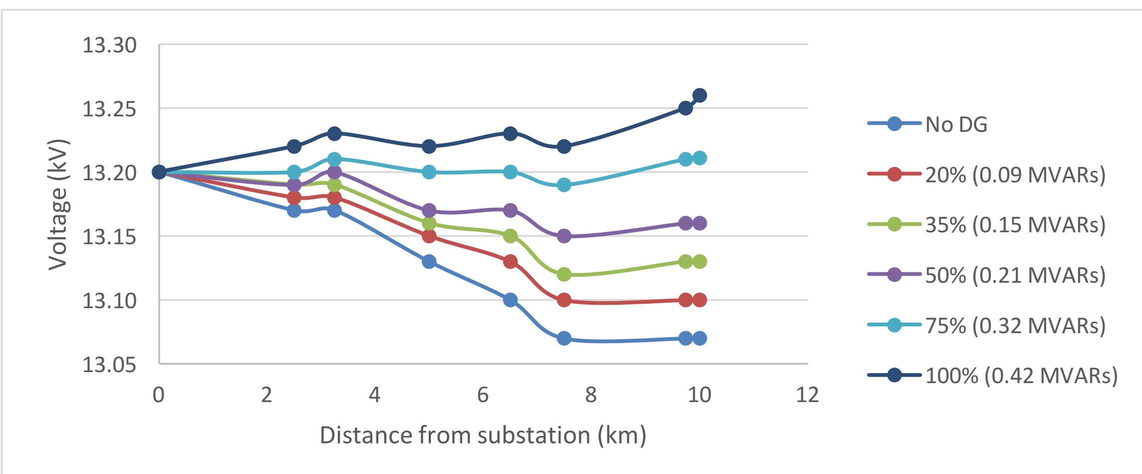

Figure A.7.2.2 Voltage along the feeder with DG at end of feeder

A.7.3 8am-11am

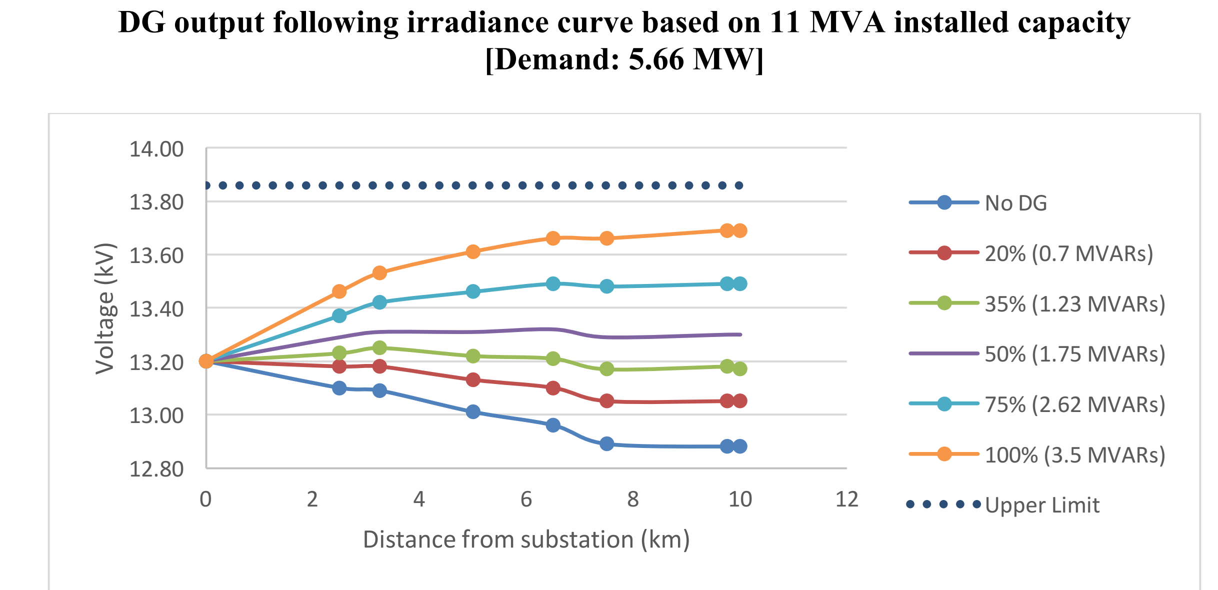

Figure A.7.3.1 Voltage along the feeder with DG evenly distributed

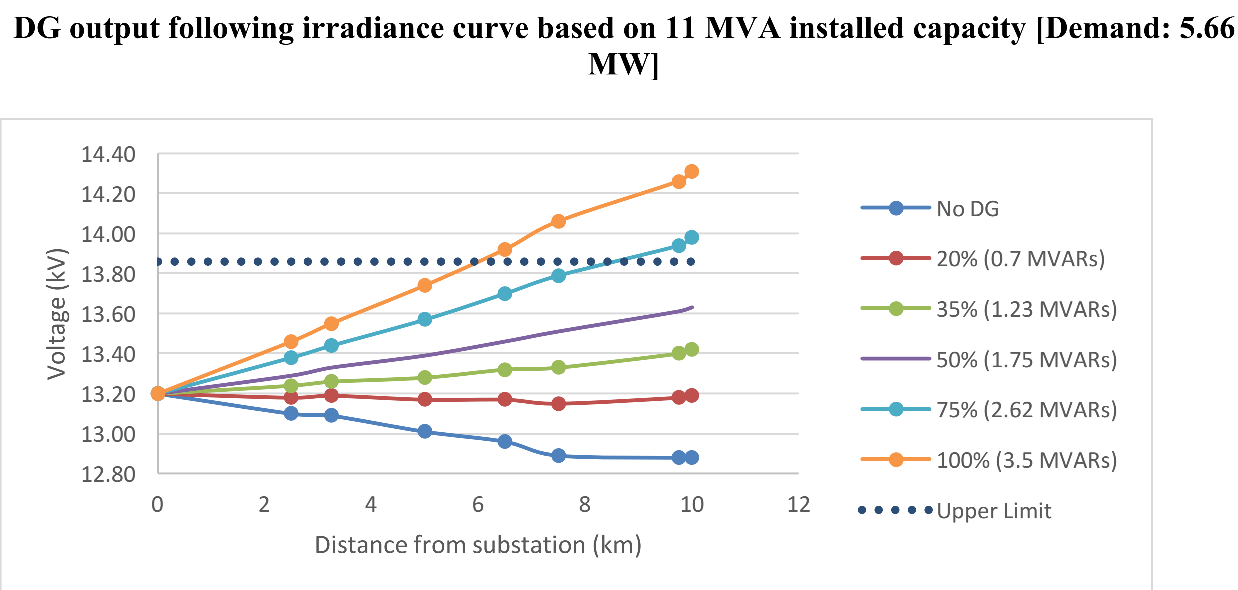

Figure A.7.3.2 Voltage along the feeder with DG at end of feeder

A.7.4 11am-4pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

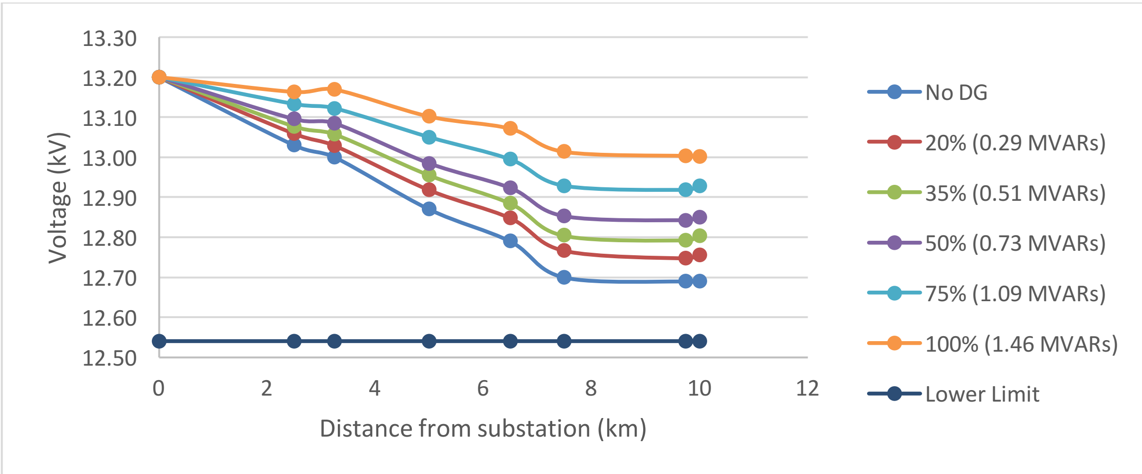

Figure A.7.4.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 7.35 MW]

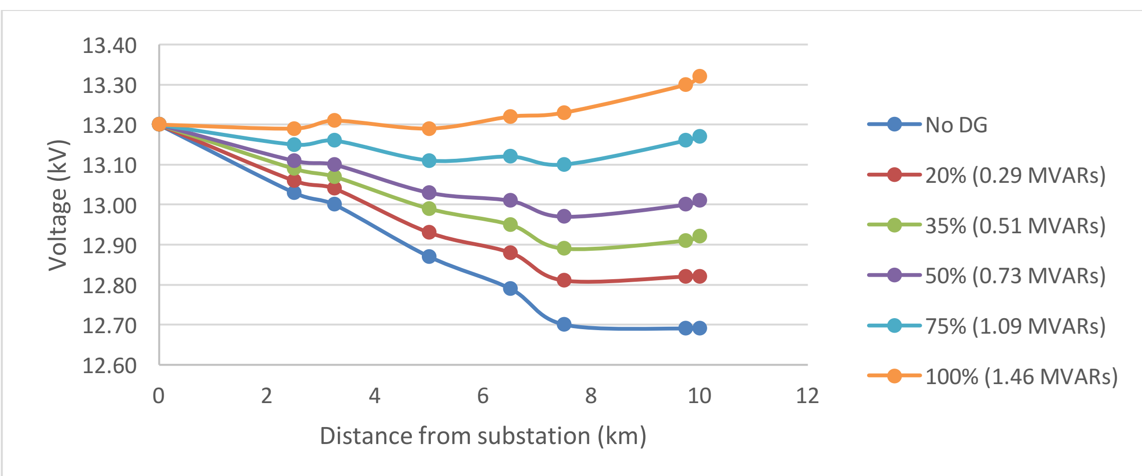

Figure A.7.4.2 Voltage along the feeder with DG evenly distributed

A.7.5 4pm-7pm

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

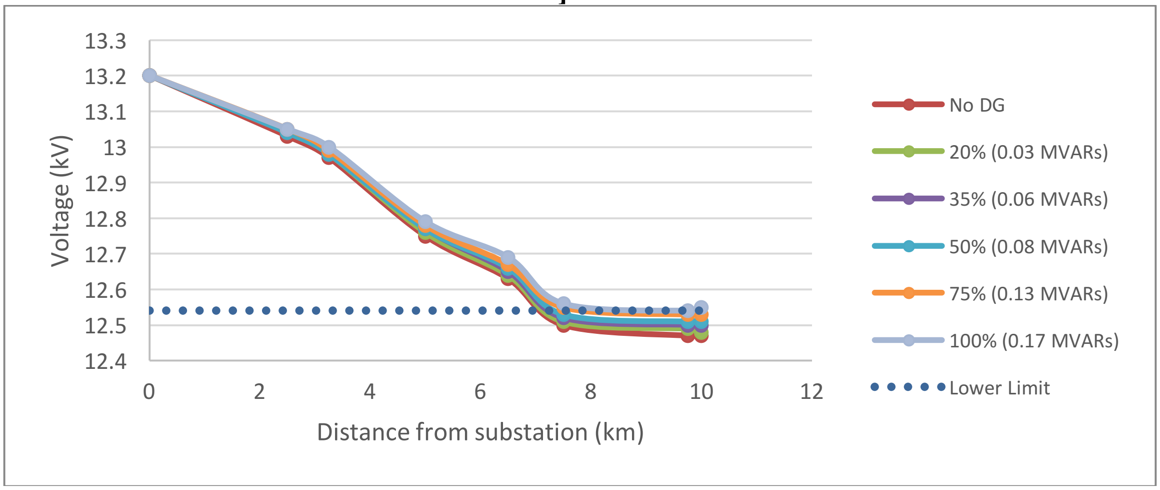

Figure A.7.5.1 Voltage along the feeder with DG evenly distributed

DG output following irradiance curve based on 11 MVA installed capacity [Demand: 10.45 MW]

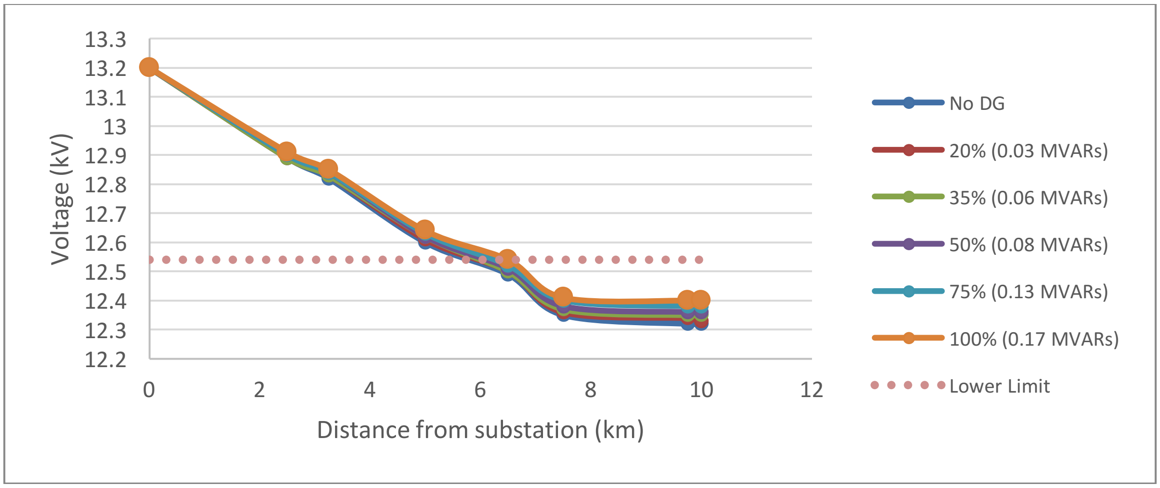

Figure A.7.5.2 Voltage along the feeder with DG at end of feeder

APPENDIX B- Percentages of voltage improvement

B.1 Voltage regulation on sunny day

B.1.1 4am-8am

B.1.1.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.14 %	*	*	*	*
3.5	0.22 %	*	*	*	*
5	0.29 %	*	*	*	*
6.5	0.36 %	*	*	*	*
7.5	0.36 %	*	*	*	*
9.75	0.44 %	*	*	*	*
10	0.44 %	*	*	*	*

B.1.2 8am-11am

B.1.2.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.29 %	0.44 %	0.58 %	*	*
3.5	0.29 %	0.51 %	0.65 %	*	*
5	0.44 %	0.80 %	1.10 %	*	*
6.5	0.59 %	0.95 %	1.39 %	*	*
7.5	0.66 %	1.18 %	1.69 %	*	*
9.75	0.66 %	1.25 %	1.77 %	*	*
10	0.66 %	1.33 %	1.84 %	*	*

B.1.2.1 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.29 %	*	*	*	*
3.5	0.36 %	*	*	*	*
5	0.66 %	*	*	*	*
6.5	0.88 %	*	*	*	*
7.5	1.33 %	*	*	*	*
9.75	1.62 %	*	*	*	*
10	1.84 %	*	*	*	*

B.1.3 11am-4pm

B.1.3.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.44 %	0.73 %	1.02 %	*	*
3.5	0.51 %	0.88 %	1.24 %	*	*
5	0.89 %	1.48 %	1.99 %	*	*
6.5	1.04 %	1.78 %	2.45 %	*	*
7.5	1.27 %	2.17 %	2.91 %	*	*
9.75	1.35 %	2.24 %	3.14 %	*	*
10	1.42 %	2.32 %	3.22 %	*	*

B.1.3.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.55 %	*	*	*	*
3.5	2.00 %	*	*	*	*
5	3.16 %	*	*	*	*
6.5	3.95 %	*	*	*	*
7.5	5.07 %	*	*	*	*
9.75	5.85 %	*	*	*	*
10	6.08 %	*	*	*	*

B.1.4 4pm-7pm

B.1.4.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.29 %	0.52 %	0.74 %	1.11 %	1.40 %
3.5	0.44 %	0.74 %	0.96 %	1.41 %	1.78 %
5	0.60 %	1.05 %	1.43 %	2.11 %	2.71 %
6.5	0.76 %	1.29 %	1.82 %	2.58 %	3.27 %
7.5	0.84 %	1.46 %	2.07 %	2.99 %	3.91 %
9.75	0.92 %	1.62 %	2.23 %	3.31 %	4.23 %
10	0.92 %	1.62 %	2.23 %	3.23 %	4.23 %

B.1.4.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.44 %	0.66 %	*	*	*
3.5	0.59 %	0.89 %	*	*	*
5	0.90 %	1.51 %	*	*	*
6.5	1.22 %	1.98 %	*	*	*
7.5	1.61 %	2.69 %	*	*	*
9.75	2.08 %	3.46 %	*	*	*
10	2.23 %	3.69 %	*	*	*

B.2 Reactive power supply on sunny day (1.05 p.u voltage)

B.2.1 4pm-7pm

B.2.1.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.96 %	1.62 %	*	*	*
3.5	1.19 %	2.08 %	*	*	*
5	1.66 %	2.86 %	*	*	*
6.5	1.98 %	3.42 %	*	*	*
7.5	2.15 %	3.76 %	*	*	*
9.75	2.31 %	3.92 %	*	*	*
10	2.31 %	3.92 %	*	*	*

B.2.1.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.96 %	*	*	*	*
3.5	1.33 %	*	*	*	*
5	2.11 %	*	*	*	*
6.5	2.81 %	*	*	*	*
7.5	3.45 %	*	*	*	*
9.75	4.08 %	*	*	*	*
10	4.23 %	*	*	*	*

B.3 Reactive power supply on sunny day (1.00 p.u voltage)

B.3.1 4am-8am

B.3.1.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.23 %	0.38 %	0.61 %	0.91 %	1.21 %
3.5	0.30 %	0.53 %	0.76 %	1.14 %	1.44 %
5	0.38 %	0.69 %	0.99 %	1.52 %	2.06 %
6.5	0.53 %	0.92 %	1.22 %	1.83 %	2.44 %
7.5	0.54 %	0.92 %	1.30 %	1.99 %	2.68 %
9.75	0.54 %	0.99 %	1.38 %	2.07 %	2.75 %
10	0.54 %	0.99 %	1.38 %	2.07 %	2.75 %

B.3.1.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.23 %	0.23 %	0.61 %	0.91 %	1.21 %
3.5	0.30 %	0.46 %	0.84 %	1.21 %	1.59 %
5	0.53 %	0.91 %	1.29 %	1.90 %	2.59 %
6.5	0.76 %	1.30 %	1.76 %	2.60 %	3.44 %
7.5	0.84 %	1.53 %	2.14 %	3.14 %	4.13 %
9.75	0.99 %	1.76 %	2.45 %	3.67 %	4.90 %
10	0.99 %	1.84 %	2.60 %	3.83 %	5.05 %

B.3.2 8am-11am

B.3.2.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.07 %	1.83 %	2.60 %	*	*
3.5	1.30 %	2.22 %	3.13 %	*	*
5	1.77 %	3.00 %	4.30 %	*	*
6.5	2.08 %	3.55 %	5.09 %	*	*
7.5	2.33 %	3.96 %	5.59 %	*	*
9.75	2.41 %	4.19 %	5.82 %	*	*
10	2.41 %	4.11 %	5.82 %	*	*

B.3.2.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.15 %	1.83 %	*	*	*
3.5	1.38 %	2.37 %	*	*	*
5	2.23 %	3.77 %	*	*	*
6.5	2.93 %	5.02 %	*	*	*
7.5	3.65 %	6.13 %	*	*	*
9.75	4.27 %	7.22 %	*	*	*
10	4.43 %	7.45 %	*	*	*

B.3.3 11am-4pm

B.3.3.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.77 %	2.99 %	*	*	*
3.5	2.15 %	3.69 %	*	*	*
5	2.95 %	5.13 %	*	*	*
6.5	3.60 %	6.10 %	*	*	*
7.5	3.94 %	6.69 %	*	*	*
9.75	4.10 %	6.93 %	*	*	*
10	4.02 %	6.93 %	*	*	*

B.3.3.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.77 %	*	*	*	*
3.5	2.31 %	*	*	*	*
5	3.73 %	*	*	*	*
6.5	5.00 %	*	*	*	*
7.5	6.06 %	*	*	*	*
9.75	7.09 %	*	*	*	*
10	7.33 %	*	*	*	*

B.3.4 4pm-7pm

B.3.4.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.00 %	0.69 %	1.46 %	2.61 %	3.76 %
3.5	0.15 %	1.08 %	2.00 %	3.47 %	4.93 %
5	0.71 %	1.96 %	3.29 %	5.33 %	7.37 %
6.5	1.03 %	2.61 %	4.12 %	6.57 %	8.95 %
7.5	1.20 %	2.96 %	4.64 %	7.28 %	9.92 %
9.75	1.28 %	3.13 %	4.89 %	7.70 %	10.43 %
10	1.28 %	3.13 %	4.89 %	7.70 %	10.43 %

B.3.4.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.00 %	1.84 %	1.38 %	*	*
3.5	0.31 %	2.39 %	2.16 %	*	*
5	1.18 %	3.84 %	4.24 %	*	*
6.5	1.90 %	5.15 %	6.02 %	*	*
7.5	2.56 %	6.24 %	7.60 %	*	*
9.75	3.29 %	7.46 %	9.22 %	*	*
10	3.37 %	7.70 %	9.54 %	*	*

B.4 Reactive power supply on sunny day (0.95 p.u voltage)

B.4.1 4am-8am

B.4.1.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.32 %	0.48 %	0.72 %	1.04 %	1.36 %
3.5	0.32 %	0.56 %	0.80 %	1.28 %	1.68 %
5	0.48 %	0.88 %	1.20 %	1.77 %	2.33 %
6.5	0.56 %	0.97 %	1.37 %	2.01 %	2.74 %
7.5	0.65 %	1.05 %	1.53 %	2.26 %	2.99 %
9.75	0.65 %	1.13 %	1.61 %	2.34 %	3.07 %
10	0.65 %	1.13 %	1.53 %	2.34 %	3.07 %

B.4.1.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.32 %	0.56 %	0.72 %	1.04 %	1.44 %
3.5	0.40 %	0.64 %	0.96 %	1.36 %	1.84 %
5	0.64 %	1.12 %	1.53 %	2.25 %	2.89 %
6.5	0.80 %	1.37 %	1.93 %	2.90 %	3.78 %
7.5	0.97 %	1.69 %	2.42 %	3.55 %	4.60 %
9.75	1.13 %	2.02 %	2.82 %	4.12 %	5.41 %
10	1.21 %	2.02 %	2.91 %	4.28 %	5.41 %

B.4.2 8am-11am

B.4.2.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.13 %	1.93 %	2.73 %	4.10 %	5.31 %
3.5	1.45 %	2.42 %	3.46 %	5.07 %	6.60 %
5	2.03 %	3.41 %	4.79 %	7.06 %	9.16 %
6.5	2.36 %	3.99 %	5.62 %	8.31 %	10.83 %
7.5	2.54 %	4.34 %	6.14 %	9.00 %	11.78 %
9.75	2.62 %	4.59 %	6.39 %	9.42 %	12.29 %
10	2.62 %	4.59 %	6.39 %	9.42 %	12.29 %

B.4.2.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.21 %	2.01 %	2.73 %	*	*
3.5	1.53 %	2.66 %	3.62 %	*	*
5	2.51 %	4.22 %	5.84 %	*	*
6.5	3.09 %	5.54 %	7.65 %	*	*
7.5	4.01 %	6.71 %	9.33 %	*	*
9.75	4.67 %	7.94 %	10.97 %	*	*
10	4.83 %	8.19 %	11.38 %	*	*

B.4.3 11am-4pm

B.4.3.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.94 %	3.32 %	4.69 %	6.72 %	*
3.5	2.35 %	4.06 %	5.68 %	8.27 %	*
5	3.36 %	5.74 %	7.96 %	11.57 %	*
6.5	3.96 %	6.77 %	9.41 %	13.61 %	*
7.5	4.32 %	7.40 %	10.31 %	14.96 %	*
9.75	4.50 %	7.74 %	10.74 %	15.57 %	*
10	4.50 %	7.74 %	10.74 %	15.57 %	*

B.4.3.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	2.02 %	3.24 %	*	*	*
3.5	2.60 %	4.22 %	*	*	*
5	4.18 %	6.89 %	*	*	*
6.5	5.45 %	9.08 %	*	*	*
7.5	6.65 %	11.06 %	*	*	*
9.75	7.91 %	13.07 %	*	*	*
10	8.16 %	13.49 %	*	*	*

B.4.4 4pm-7pm

B.4.4.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.13 %	1.94 %	2.75 %	4.13 %	5.34 %
3.5	1.48 %	2.55 %	3.54 %	5.19 %	6.75 %
5	2.01 %	3.52 %	4.95 %	7.29 %	9.47 %
6.5	2.46 %	4.15 %	5.93 %	8.64 %	11.26 %
7.5	2.66 %	4.63 %	6.51 %	0.94 %	12.43 %
9.75	2.84 %	4.81 %	6.79 %	9.97 %	12.97 %
10	2.84 %	4.81 %	6.79 %	9.97 %	12.97 %

B.4.4.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	1.13 %	1.94 %	2.75 %	3.88 %	*
3.5	1.56 %	2.63 %	3.70 %	5.27 %	*
5	2.51 %	4.27 %	5.95 %	8.47 %	*
6.5	3.39 %	5.76 %	7.96 %	11.35 %	*
7.5	4.20 %	7.11 %	9.85 %	14.05 %	*
9.75	4.98 %	8.42 %	11.60 %	16.58 %	*
10	5.15 %	8.68 %	12.03 %	17.18 %	*

B.5 Voltage regulation on cloudy day

B.5.1 4am-8am

B.5.1.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.07 %	0.07 %	0.07 %	0.07 %	0.07 %
3.5	0.07 %	0.07 %	0.07 %	0.07 %	0.14 %
5	0.07 %	0.07 %	0.15 %	0.15 %	0.22 %
6.5	0.07 %	0.07 %	0.15 %	0.15 %	0.22 %
7.5	0.07 %	0.07 %	0.15 %	0.15 %	0.22 %
9.75	0.07 %	0.07 %	0.15 %	0.15 %	0.22 %
10	0.07 %	0.07 %	0.15 %	0.15 %	0.22 %

B.5.1.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.07 %	0.14 %	*	*	*
3.5	0.14 %	0.14 %	*	*	*
5	0.22 %	0.29 %	*	*	*
6.5	0.22 %	0.36 %	*	*	*
7.5	0.29 %	0.51 %	*	*	*
9.75	0.44 %	0.73 %	*	*	*
10	0.44 %	0.73 %	*	*	*

B.5.2 8am-11am

B.5.2.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.15 %	0.22 %	0.36 %	0.51 %	0.65 %
3.5	0.15 %	0.36 %	0.36 %	0.58 %	0.73 %
5	0.22 %	0.58 %	0.58 %	0.88 %	1.17 %
6.5	0.29 %	0.73 %	0.73 %	1.10 %	1.47 %
7.5	0.37 %	0.88 %	0.88 %	1.33 %	1.77 %
9.75	0.37 %	0.96 %	0.96 %	1.40 %	1.84 %
10	0.37 %	1.03 %	1.03 %	1.47 %	1.92 %

B.5.2.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.15 %	0.29 %	*	*	*
3.5	0.22 %	0.29 %	*	*	*
5	0.37 %	0.58 %	*	*	*
6.5	0.51 %	0.88 %	*	*	*
7.5	0.74 %	1.25 %	*	*	*
9.75	0.88 %	1.55 %	*	*	*
10	1.03 %	1.77 %	*	*	*

B.5.3 11am-4pm

B.5.3.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.07 %	0.07 %	0.15 %	0.22 %	0.29 %
3.5	0.07 %	0.15 %	0.22 %	0.29 %	0.37 %
5	0.15 %	0.22 %	0.30 %	0.44 %	0.59 %
6.5	0.15 %	0.22 %	0.37 %	0.52 %	0.67 %
7.5	0.15 %	0.30 %	0.45 %	0.67 %	0.90 %
9.75	0.15 %	0.30 %	0.45 %	0.67 %	0.90 %
10	0.22 %	0.37 %	0.52 %	0.75 %	0.97 %

B.5.3.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.07 %	0.15 %	0.22 %	0.29 %	0.36 %
3.5	0.07 %	0.15 %	0.22 %	0.37 %	0.44 %
5	0.22 %	0.30 %	0.44 %	0.66 %	0.81 %
6.5	0.22 %	0.37 %	0.59 %	0.82 %	1.11 %
7.5	0.37 %	0.60 %	0.82 %	1.20 %	1.57 %
9.75	0.37 %	0.67 %	1.05 %	1.50 %	2.39 %
10	0.52 %	0.82 %	1.20 %	1.72 %	2.25 %

B.5.4 4pm-7pm

B.5.4.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %
3.5	0.07 %	0.07 %	0.07 %	0.07 %	0.07 %
5	0.00 %	0.00 %	0.08 %	0.08 %	0.08 %
6.5	0.08 %	0.08 %	0.08 %	0.08 %	0.15 %
7.5	0.00 %	0.00 %	0.08 %	0.08 %	0.08 %
9.75	0.00 %	0.08 %	0.08 %	0.08 %	0.15 %
10	0.00 %	0.00 %	0.08 %	0.08 %	0.15 %

B.5.4.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %
3.5	0.07 %	0.07 %	0.07 %	0.07 %	0.15 %
5	0.00 %	0.08 %	0.08 %	0.08 %	0.15 %
6.5	0.08 %	0.08 %	0.08 %	0.15 %	0.23 %
7.5	0.00 %	0.08 %	0.08 %	0.15 %	0.23 %
9.75	0.08 %	0.08 %	0.15 %	0.23 %	0.31 %
10	0.08 %	0.08 %	0.15 %	0.23 %	0.31 %

B.6 Reactive power supply on cloudy day (1.05 p.u voltage)

B.6.1 4am-8am

B.6.1.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.07 %	0.14 %	0.22 %	*	*
3.5	0.14 %	0.14 %	0.22 %	*	*
5	0.15 %	0.22 %	0.29 %	*	*
6.5	0.15 %	0.22 %	0.36 %	*	*
7.5	0.15 %	0.22 %	0.36 %	*	*
9.75	0.15 %	0.29 %	0.36 %	*	*
10	0.15 %	0.22 %	0.36 %	*	*

B.6.1.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.07 %	0.14 %	0.22 %	*	*
3.5	0.14 %	0.22 %	0.22 %	*	*
5	0.15 %	0.29 %	0.36 %	*	*
6.5	0.22 %	0.36 %	0.51 %	*	*
7.5	0.22 %	0.44 %	0.58 %	*	*
9.75	0.29 %	0.44 %	0.66 %	*	*
10	0.29 %	0.44 %	0.66 %	*	*

B.6.2 8am-11am

B.6.2.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.51 %	*	*	*	*
3.5	0.58 %	*	*	*	*
5	0.88 %	*	*	*	*
6.5	1.03 %	*	*	*	*
7.5	1.11 %	*	*	*	*
9.75	1.18 %	*	*	*	*
10	1.18 %	*	*	*	*

B.6.2.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.58 %	*	*	*	*
3.5	0.65 %	*	*	*	*
5	1.10 %	*	*	*	*
6.5	1.47 %	*	*	*	*
7.5	1.77 %	*	*	*	*
9.75	2.14 %	*	*	*	*
10	2.14 %	*	*	*	*

B.6.3 11am-4pm

B.6.3.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.22 %	0.36 %	0.51 %	0.80 %	1.02 %
3.5	0.22 %	0.44 %	0.66 %	0.95 %	1.32 %
5	0.37 %	0.66 %	0.89 %	1.40 %	1.85 %
6.5	0.45 %	0.74 %	1.04 %	1.63 %	2.15 %
7.5	0.52 %	0.82 %	1.20 %	1.79 %	2.39 %
9.75	0.45 %	0.82 %	1.20 %	1.80 %	2.47 %
10	0.52 %	0.90 %	1.27 %	1.87 %	2.54 %

B.6.3.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.22 %	0.36 %	0.58 %	0.80 %	*
3.5	0.22 %	0.51 %	0.73 %	1.10 %	*
5	0.44 %	0.81 %	1.18 %	1.77 %	*
6.5	0.59 %	1.11 %	1.56 %	2.30 %	*
7.5	0.75 %	1.35 %	1.94 %	2.84 %	*
9.75	0.90 %	1.57 %	2.24 %	3.29 %	*
10	0.97 %	1.65 %	2.40 %	3.52 %	*

B.6.4 4pm-7pm

B.6.4.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.00 %	0.00 %	0.00 %	0.07 %	0.07 %
3.5	0.07 %	0.07 %	0.15 %	0.15 %	0.22 %
5	0.08 %	0.08 %	0.08 %	0.15 %	0.23 %
6.5	0.08 %	0.08 %	0.15 %	0.23 %	0.30 %
7.5	0.08 %	0.08 %	0.15 %	0.31 %	0.31 %
9.75	0.08 %	0.08 %	0.15 %	0.31 %	0.31 %
10	0.08 %	0.08 %	0.15 %	0.31 %	0.31 %

B.6.4.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.00 %	0.00 %	0.07 %	0.07 %	0.07 %
3.5	0.07 %	0.07 %	0.15 %	0.15 %	0.24 %
5	0.08 %	0.08 %	0.15 %	0.23 %	0.30 %
6.5	0.08 %	0.15 %	0.23 %	0.30 %	0.38 %
7.5	0.08 %	0.15 %	0.23 %	0.31 %	0.46 %
9.75	0.15 %	0.23 %	0.31 %	0.38 %	0.54 %
10	0.08 %	0.23 %	0.31 %	0.38 %	0.54 %

B.7 Reactive power supply on cloudy day (1.00 p.u voltage)

B.7.1 4am-8am

B.7.1.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.08 %	0.08 %	0.15 %	0.23 %	0.30 %
3.5	0.08 %	0.15 %	0.15 %	0.30 %	0.38 %
5	0.08 %	0.15 %	0.23 %	0.38 %	0.53 %
6.5	0.15 %	0.23 %	0.38 %	0.53 %	0.69 %
7.5	0.15 %	0.23 %	0.38 %	0.54 %	0.77 %
9.75	0.15 %	0.23 %	0.38 %	0.54 %	0.77 %
10	0.15 %	0.23 %	0.38 %	0.54 %	0.77 %

B.7.1.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.08 %	0.15 %	0.15 %	0.23 %	0.38 %
3.5	0.08 %	0.15 %	0.23 %	0.30 %	0.46 %
5	0.15 %	0.23 %	0.30 %	0.53 %	0.69 %
6.5	0.23 %	0.38 %	0.53 %	0.76 %	0.99 %
7.5	0.23 %	0.38 %	0.61 %	0.92 %	1.15 %
9.75	0.23 %	0.46 %	0.69 %	1.07 %	1.38 %
10	0.23 %	0.46 %	0.69 %	1.07 %	1.45 %

B.7.2 8am-11am

B.7.2.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.61 %	0.99 %	1.45 %	2.06 %	2.75 %
3.5	0.69 %	1.22 %	1.68 %	2.52 %	3.36 %
5	0.92 %	1.61 %	2.31 %	3.46 %	4.61 %
6.5	1.08 %	1.93 %	2.78 %	4.09 %	5.40 %
7.5	1.24 %	2.17 %	3.10 %	4.58 %	5.97 %
9.75	1.32 %	2.33 %	3.26 %	4.74 %	6.29 %
10	1.32 %	2.25 %	3.26 %	4.74 %	6.29 %

B.7.2.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.61 %	1.07 %	1.45 %	*	*
3.5	0.76 %	1.30 %	1.83 %	*	*
5	1.23 %	2.08 %	2.92 %	*	*
6.5	1.62 %	2.78 %	3.86 %	*	*
7.5	2.02 %	3.41 %	4.81 %	*	*
9.75	2.33 %	4.04 %	5.67 %	*	*
10	2.41 %	4.19 %	5.82 %	*	*

B.7.3 11am-4pm

B.7.3.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.23 %	0.38 %	0.54 %	0.77 %	1.00 %
3.5	0.23 %	0.46 %	0.62 %	0.92 %	1.31 %
5	0.39 %	0.62 %	0.85 %	1.40 %	1.79 %
6.5	0.47 %	0.70 %	1.02 %	1.56 %	2.19 %
7.5	0.55 %	0.79 %	1.18 %	1.81 %	2.44 %
9.75	0.47 %	0.79 %	1.18 %	1.81 %	2.44 %
10	0.55 %	0.87 %	1.26 %	1.81 %	2.44 %

B.7.3.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.23 %	0.46 %	0.61 %	0.92 %	1.23 %
3.5	0.31 %	0.54 %	0.77 %	1.23 %	1.62 %
5	0.47 %	0.93 %	1.24 %	1.86 %	2.49 %
6.5	0.70 %	1.25 %	1.72 %	2.58 %	3.36 %
7.5	0.87 %	1.50 %	2.13 %	3.15 %	4.17 %
9.75	1.02 %	1.73 %	2.44 %	3.70 %	4.81 %
10	1.02 %	1.81 %	2.52 %	3.78 %	4.96 %

B.7.4 4pm-7pm

B.7.4.1 DG evenly distributed

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.00 %	0.00 %	0.08 %	0.08 %	0.16 %
3.5	0.08 %	0.08 %	0.16 %	0.16 %	0.23 %
5	0.08 %	0.16 %	0.16 %	0.24 %	0.32 %
6.5	0.08 %	0.08 %	0.16 %	0.24 %	0.40 %
7.5	0.08 %	0.16 %	0.24 %	0.40 %	0.49 %
9.75	0.16 %	0.24 %	0.32 %	0.49 %	0.65 %
10	0.00 %	0.24 %	0.32 %	0.49 %	0.65 %

B.7.4.2 DG at end of feeder

Distance (km)	20% DG	35% DG	50% DG	75% DG	100% DG
2	0.00 %	0.00 %	0.08 %	0.08 %	0.16 %
3.5	0.08 %	0.08 %	0.16 %	0.16 %	0.23 %
5	0.08 %	0.16 %	0.16 %	0.16 %	0.32 %
6.5	0.08 %	0.08 %	0.16 %	0.24 %	0.40 %
7.5	0.08 %	0.16 %	0.24 %	0.40 %	0.49 %
9.75	0.16 %	0.24 %	0.32 %	0.49 %	0.65 %
10	0.08 %	0.24 %	0.32 %	0.49 %	0.65 %

APPENDIX C- Marginal Costs

C.1 Active Power Marginal Costs

C.1.1 4am-8am

Distance	No DG ($/MWh)	20% DG ($/MWh)	35% DG ($/MWh)	50% DG ($/MWh)	75% DG ($/MWh)	100% DG ($/MWh)
0 km	3.203	3.188	*	*	*	*
2 km	3.221	3.204	*	*	*	*
3.5 km	3.229	3.211	*	*	*	*
5 km	3.246	3.227	*	*	*	*
6.5 km	3.267	3.246	*	*	*	*
7.5 km	3.293	3.270	*	*	*	*
9.75 km	3.300	3.276	*	*	*	*
10 km	3.300	3.277	*	*	*	*
Half Lat. 1	3.224	3.207	*	*	*	*
End Lat. 1	3.225	3.208	*	*	*	*
Half Lat. 2	3.250	3.231	*	*	*	*
End Lat. 2	3.251	3.232	*	*	*	*
Half Lat. 3	3.297	3.274	*	*	*	*
End Lat.3	3.298	3.275	*	*	*	*

C.1.2 8am-11am

Distance	No DG ($/MWh)	20% DG ($/MWh)	35% DG ($/MWh)	50% DG ($/MWh)	75% DG ($/MWh)	100% DG ($/MWh)
0 km	3.287	3.219	3.172	3.123	*	*
2 km	3.812	3.238	3.187	3.133	*	*
3.5 km	3.324	3.247	3.194	3.138	*	*
5 km	3.350	3.267	3.210	3.150	*	*
6.5 km	3.380	3.289	3.228	3.163	*	*
7.5 km	3.419	3.320	3.252	3.182	*	*
9.75 km	3.430	3.328	3.259	3.187	*	*
10 km	3.430	3.328	3.259	3.187	*	*
Half Lat. 1	3.318	3.242	3.189	3.134	*	*
End Lat. 1	3.319	3.243	3.190	3.135	*	*
Half Lat. 2	3.356	3.271	3.212	3.151	*	*
End Lat. 2	3.357	3.272	3.214	3.152	*	*
Half Lat. 3	3.425	3.323	3.254	3.182	*	*
End Lat.3	3.427	3.325	3.255	3.184	*	*

C.1.3 11am-4pm

Distance	No DG ($/MWh)	20% DG ($/MWh)	35% DG ($/MWh)	50% DG ($/MWh)	75% DG ($/MWh)	100% DG ($/MWh)
0 km	3.376	3.264	3.178	3.123	*	*
2 km	3.410	3.287	3.193	3.133	*	*
3.5 km	3.426	3.297	3.200	3.138	*	*
5 km	3.462	3.323	3.218	3.150	*	*
6.5 km	3.503	3.350	3.237	3.163	*	*
7.5 km	3.557	3.388	3.264	3.182	*	*
9.75 km	3.572	3.398	3.272	3.187	*	*
10 km	3.572	3.399	3.272	3.187	*	*
Half Lat. 1	3.418	3.291	3.195	3.134	*	*
End Lat. 1	3.421	3.293	3.196	3.135	*	*
Half Lat. 2	3.420	3.327	3.220	3.151	*	*
End Lat. 2	3.472	3.328	3.221	3.152	*	*
Half Lat. 3	3.566	3.392	3.266	3.182	*	*
End Lat.3	3.568	3.394	3.267	3.184	*	*

C.1.4 4pm-7pm

Distance	No DG ($/MWh)	20% DG ($/MWh)	35% DG ($/MWh)	50% DG ($/MWh)	75% DG ($/MWh)	100% DG ($/MWh)
0 km	3.535	3.467	3.418	3.368	3.285	3.203
2 km	3.587	3.511	3.457	3.401	3.311	3.220
3.5 km	3.612	3.531	3.476	3.417	3.323	3.229
5 km	3.667	3.578	3.518	3.454	3.352	3.251
6.5 km	3.731	3.632	3.565	3.495	3.383	3.273
7.5 km	3.816	3.704	3.630	3.552	3.428	3.307
9.75 km	3.839	3.724	3.647	3.568	3.441	3.317
10 km	3.840	3.724	3.648	3.568	3.441	3.317
Half Lat. 1	3.599	3.520	3.465	3.407	3.314	3.221
End Lat. 1	3.602	3.522	3.467	3.410	3.316	3.223
Half Lat. 2	3.679	3.588	3.525	3.460	3.355	3.251
End Lat. 2	3.682	3.591	3.528	3.463	3.358	3.254
Half Lat. 3	3.830	3.715	3.638	3.558	3.431	3.307
End Lat.3	3.833	3.718	3.641	3.561	3.434	3.310

C.2 Reactive Marginal Costs

C.2.1 4am-8am

Distance	No DG ($/MVARh)	20% DG ($/MVARh)	35% DG ($/MVARh)	50% DG ($/MVARh)	75% DG ($/MVARh)	100% DG ($/MVARh)
0 km	-	-	-	-	-	-
2 km	-0.001	-0.003	-0.004	-0.005	-0.007	-0.008
3.5 km	-0.002	-0.004	-0.006	-0.008	-0.010	-0.013
5 km	-0.003	-0.006	-0.009	-0.011	-0.015	-0.019
6.5 km	-0.005	-0.010	-0.014	-0.017	-0.024	-0.029
7.5 km	-0.010	-0.016	-0.022	-0.027	-0.035	-0.043
9.75 km	-0.009	-0.016	-0.022	-0.027	-0.036	-0.044
10 km	-0.009	-0.016	-0.022	-0.027	-0.036	-0.044
Half Lat. 1	0.000	-0.002	-0.004	-0.005	-0.008	-0.010
End Lat. 1	0.000	-0.002	-0.004	-0.005	-0.008	-0.010
Half Lat. 2	-0.002	-0.006	-0.009	-0.012	-0.017	-0.021
End Lat. 2	-0.002	-0.006	-0.009	-0.012	-0.017	-0.021
Half Lat. 3	-0.009	-0.016	-0.023	-0.027	-0.037	-0.045
End Lat.3	-0.009	-0.016	-0.023	-0.027	-0.037	-0.045

C.2.2 8am-11am

Distance	No DG ($/MVARh)	20% DG ($/MVARh)	35% DG ($/MVARh)	50% DG ($/MVRh)	75% DG ($/MVARh)	100% DG ($/MVARh)
0 km	-	-	-	-	-	-
2 km	0.001	-0.005	-0.010	-0.014	-0.022	-0.029
3.5 km	0.000	-0.008	-0.016	-0.022	-0.032	-0.043
5 km	0.002	-0.012	0.023	-0.033	-0.050	-0.067
6.5 km	0.002	-0.019	-0.034	-0.048	-0.076	-0.100
7.5 km	-0.003	-0.030	-0.050	-0.069	-0.105	-0.140
9.75 km	-0.001	-0.031	-0.052	-0.072	-0.111	-0.148
10 km	-0.001	-0.031	-0.052	-0.072	-0.110	-0.148
Half Lat. 1	0.002	-0.006	-0.013	-0.019	-0.029	-0.039
End Lat. 1	0.002	-0.006	-0.013	-0.018	-0.028	-0.038
Half Lat. 2	0.002	-0.013	-0.026	-0.037	-0.057	-0.077
End Lat. 2	0.003	-0.013	-0.026	-0.037	-0.057	-0.076
Half Lat. 3	-0.002	-0.031	-0.053	-0.074	-0.112	-0.151
End Lat.3	-0.002	-0.031	-0.053	-0.073	-0.112	-0.151

C.2.3 11am-4pm

Distance	No DG ($/MVARh)	20% DG ($/MVARh)	35% DG ($/MVARh)	50% DG ($/MVARh)	75% DG ($/MVARh)	100% DG ($/MVARh)
0 km	0.000	-	-	-	*	*
2 km	0.003	-0.007	-0.016	-0.024	*	*
3.5 km	0.004	-0.011	-0.024	-0.035	*	*
5 km	0.007	-0.017	-0.036	-0.055	*	*
6.5 km	0.008	-0.026	-0.054	-0.083	*	*
7.5 km	0.006	-0.041	-0.078	-0.116	*	*
9.75 km	0.008	-0.042	-0.081	-0.122	*	*
10 km	0.008	-0.042	-0.081	-0.122	*	*
Half Lat. 1	0.004	-0.009	-0.021	-0.031	*	*
End Lat. 1	0.005	-0.009	-0.021	-0.031	*	*
Half Lat. 2	0.008	-0.019	-0.042	-0.063	*	*
End Lat. 2	0.008	-0.019	-0.041	-0.063	*	*
Half Lat. 3	0.008	-0.043	-0.083	-0.124	*	*
End Lat.3	0.008	-0.043	-0.083	-0.124	*	*

C.2.4 4pm-7pm

Distance	No DG ($/MVARh)	20% DG ($/MVARh)	35% DG ($/MVARh)	50% DG ($/MVARh)	75% DG ($/MVARh)	100% DG ($/MVARh)
0 km	-	-	-	-	-	-
2 km	0.008	0.002	-0.003	-0.008	-0.019	-0.027
3.5 km	0.010	0.001	-0.006	-0.012	-0.030	-0.041
5 km	0.017	0.002	-0.009	-0.020	-0.044	-0.061
6.5 km	0.022	0.000	-0.017	-0.033	-0.064	-0.089
7.5 km	0.023	-0.007	-0.030	-0.052	-0.093	-0.127
9.75 km	0.026	-0.006	-0.031	-0.054	-0.097	-0.134
10 km	0.026	-0.006	-0.031	-0.054	-0.097	-0.134
Half Lat. 1	0.009	0.000	-0.006	-0.012	-0.027	-0.037
End Lat. 1	0.009	0.001	-0.006	-0.012	-0.027	-0.037
Half Lat. 2	0.018	0.001	-0.012	-0.025	-0.051	-0.071
End Lat. 2	0.018	0.001	-0.012	-0.024	-0.051	-0.071
Half Lat. 3	0.024	-0.009	-0.033	-0.057	-0.101	-0.137
End Lat.3	0.024	-0.009	-0.033	-0.057	-0.100	-0.137

APPENDIX D- Presentation to Puerto Rico Energy Commission

September 10, 2016

Puerto Rico Energy Commission
500 Calle Roberto H. Todd
San Juan, Puerto Rico

For the attention of: Agustín F. Carbó Lugo, Esq.
Chairman
José H. Román Morales, PE
Associate Commissioner
Ángel R. Rivera de la Cruz, Esq., PE
Associate Commissioner

Dear Commissioners:

My name is Naysy López, a graduate student in Electrical Engineering at UPR-Mayagüez Campus, working on my master thesis with Dr. Efraín O'Neill-Carrillo, professor of Electrical and Computer Engineering Department at UPR-Mayagüez Campus and I appear in front this Honorable Puerto Rico Energy Commission (from now, "Commission") to present part of my master's research work on power systems, which I understand is useful to the Commission in this tariff review process.

The people of Puerto Rico, through the Legislative Assembly, have been clear and consistent in their support to the maximum use of renewable energy. Examples are the Law 114 of 2007, Law 82 and 83 of 2010, Law 57 of 2014 and recently the Law 133 of August of 2016. These laws trace the way of public policy for renewable energy, and research work carried out here in the Mayaguez Campus supports this road. An important element is the access and use of renewable energy directly by customers (residential, commercial and industrial) through systems on their areas. This operation in parallel with the electricity grid is what we call distributed generation. Currently, most of the customers with distributed generation, mostly with rooftop photovoltaic systems, are under the net metering program, established on Law 114-2007. This law expresses the following in Article 1, Mandate:

"The Puerto Rico Electric Authority is ordered and authorized to establish a net metering program that allows the interconnection to its transmission and distribution system and

the electricity feedback to customers who have installed an electric solar equipment, windmill capable of producing electrical energy…"

Parts of the relationship established by Law 114 between the Puerto Rico Electric Power Authority (PREPA) and its clients under the net metering program in its article 5 are:

a) The Puerto Rico Electric Power Authority will measure the net electricity produced or consumed by the customer during a billing period.

b) The Puerto Rico Electric Power Authority may charge the net electricity supplied to the customer.

c) The Puerto Rico Electric Power Authority may charge the customer a minimum service charge.

d) PREPA will be obliged to credit the customer that feedback the excess of kilowatt-hours generated during the billing period.

e) Any surplus of the kilowatt-hours credits accumulated by the customer feedback during the previous year will be credited in June of each year at the rate of ten (10) cents per kilowatt-hout for the seventy-five (75) surplus; the remaining twenty-five (25) percent will be granted to PREPA to distributed them in credits or rebates on public school electricity bills.

Net metering is the center of important debates in different parts of the world. On one hand, some argue that clients under net metering are being subsidized by customers who don't have net metering. The customer under net metering uses the network, but pays less for the maintenance of the network, due to the way in which traditional tariffs are made (recovering costs almost exclusively through electricity consumption). On the other hand, some net metering advocates state that social, economic and environmental benefits outweigh the cost to the system and to non-participating customers. Electricity companies in general have not determined the benefits to grid operation that come from distributed generators connected in net metering programs. An important point of the debate is when it is time for the role of incentive to renewable energy from net metering has been fulfilled.

During the research for my thesis, I have found that distributed renewable generation can provide other services to the network, beyond the electric power they provide. Many companies in the United States have been working to maximize the network services they can receive from distributed generation, among which are voltage regulation and reactive power supply to the grid. In several of these states they have made analysis to assign a value in monetary terms to each of these services to have a fair and reasonable rate for both the customer with its renewable energy system, the electric company and the rest of the customers. In this way, the power company will not only sell or buy energy to the customer, but may use other benefits provided to the network, if necessary through an agreement or contract.

My study is based on a research of what have done in other states, analyze the services mention before in a Puerto Rico distribution line and studying possible schemes to assign a monetary value to these services. It is important to clarify that it is not intended to adapt a model made in another jurisdiction and to apply it in Puerto Rico, rather it seeks to create, with the experience of other places and ours on the Island, a favorable model to the conditions we have. The main objective is to create different contract options between the client and the electricity company for the use of these services depending on the time and the service that is needed.

One of the services that generators can give is voltage regulation. Distributed generation, in addition to providing electrical power, has the benefit of improving the voltage level. This can be a great benefit especially in times of high demand in the system at times where there is a greater drop in voltage. Reactive power is another benefit that distributed generation can provide to the electrical system. Currently distributed generators are only used to generate actual power, but can be used to provide reactive power as well. This service also can result in an increase in system voltage.

On my study, I simulated several cases to analyze the real and reactive power injection for different penetrations of distributed generation, in different periods of the day, each with a different demand for a typical sunny day and a cloudy one. A demand curve similar to the residential demand profile in Puerto Rico was used modeling a typical distribution line of the Island. With the distributed generators through the distribution line on a sunny day it was observed that during the day can be injected between 35% and 50% of the demand without violating the established voltage limits. The analysis assumes that the distribution system is designed with the aim of maximizing the one of distributed renewable energy.

For the monetary value analysis that will be assigned to each service, I am studying the methods used in several US states to obtain one or several methods that adapt to the realities of Puerto Rico. This is to ensure that both, the costs and benefits of distributed generation are accounted for, and that the greater penetration of renewable energy is promoted in our system, since this has been the consistent mandate of the laws that have been presented from 2007 to the present in relation to renewable energy.

In summary, my research work establishes from the technical point of view, that if we have the will to use more renewable energy we can achieve it. There is a lack of change in the way we plan, build and operate our electrical infrastructure. If the PREPA's rates are revised to continue to support the traditional way of planning, building and operating power systems, we will not advance as far as possible the objectives set by Puerto Rico's public energy policy. I appreciate the opportunity to participate in this process and I remain available to answer any questions that you or the members of the Honorable Commission may have regarding what was presented.

Sincerely,

Naysy E. López Mercado
Electrical Engineering Graduate Student
University of Puerto Rico-Mayagüez Campus