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June 30, 2021

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Distributed Generation Cost of Service Study
Docket No. E-100, Sub 101

Dear Ms. Campbell:

Pursuant to the North Carolina Utilities Commission's June 14, 2019 *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony* and the September 5, 2019 *Order Granting Waiver*, please find enclosed Duke Energy Progress, LLC's and Duke Energy Carolinas, LLC's Distributed Generation Cost of Service Study.

If you have any questions, please do not hesitate to contact me. Thank you for your assistance with this matter.

Sincerely,

Jack E. Jirak

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Distributed Generation Cost of Service Study, in Docket No. E-100, Sub 101, has been served by electronic mail, hand delivery, or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 30th day of June, 2021.

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Distributed Generation Cost of Service Study

Docket No. E-100, Sub 101

Introduction and Overview

In response to the North Carolina Utilities Commission's ("Commission") Order Approving Revised Interconnection Standard and Requiring Reports and Testimony ("Order"), Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC" and together with DEP, "Duke" or the "Companies") hereby submit this Distributed Generation ("DG") Cost of Service ("COS") Study.

In preparing the DG COS Study, Duke engaged the FREEDM Center at North Carolina State University ("NCSU Study Team") to conduct the engineering study ("the NCSU Study"). The NCSU Study Team generated two reports: 1) "*Framework for Estimating DG Cost of Service"* which includes a literature review and interviews with field engineers and is provided as **Appendix 1** and 2) "*DG Cost of Service: Sample Case Studies"* which details a series of power flow simulations on both synthetic and actual Duke circuits and is provided as **Appendix 2**.

This summary report contains a discussion of how costs are currently being allocated to distributed generators and estimates the share of costs that are not being currently being allocated to distributed generators, and also identifies options for recovering these costs. The NCSU Study informed this approach with a few important observations: 1) that system benefits of increasing DG penetration exist up to a certain point; 2) this inflection point depends on the characteristics of the feeder and the other feeders sourced by the same transmission--to-distribution (t-d) transformer, and 3) the array of time series simulations required to characterize the inflection point are extremely intensive in terms of computing resources and engineering labor. This summary report also discusses how the Companies' Integrated System and Operations Planning ("ISOP") capabilities were used in this effort.

Finally, Duke engaged the North Carolina Advanced Energy Corporation ("AE") for stakeholder facilitation assistance. AE has been actively engaging study participants and providing technical review. The AE team generated the "*Distributed Generation Cost-of-Service Stakeholder Report"* summarizing their engagement, which is provided as **Appendix 3**.

Discussion

Cost of service studies group utility costs according to their "function." Functions include production (generation), transmission, distribution, and customer service, billing, and sales. These functionalized costs are then further grouped or classified based on the utility "operation" or service being provided and the related causation of the costs. Typical classifications include demand, energy, and customer-related costs. These two steps are combined to produce the functionalized classification of utility costs as listed below:

- Production Demand
- Production Energy
- Transmission Demand
- Distribution Demand
- Customer

DEP's unbundled cost of service lists distribution substations, and the demand related portions of primary plant, primary to secondary distribution line transformers, and secondary plant in the Distribution Demand category. DEC's unbundled cost of service lists the same distribution costs in this category; although they are presented in slightly different segments – as distribution substations, and the demand related portions of Poles, Towers and Fixtures (primary and secondary), Overhead and Underground Conductors & Conduits (primary and secondary), distribution line transformers, and other local plant (street lighting, customer premises and service direct assignments).

In the following sections, the allocation and recovery of each cost function is reviewed for impacts from DG.

Production Energy/Production Demand

The impact of DG on production energy and demand functions is directly addressed in the biennial determination of avoided cost rates. The NCSU Study examines how distribution losses are impacted by varying levels of DG penetration and concludes that even at relatively high levels of DG penetration distribution losses continue to be positively impacted.

Transmission Demand

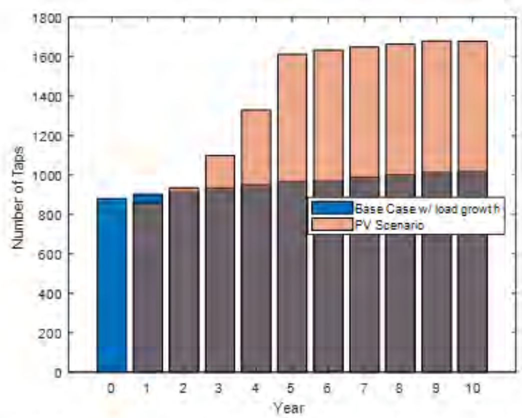
The transmission costs are allocated to retail customers based on the coincident peak demand method approved in that jurisdiction. Generators connecting to the transmission system under the Joint Open Access Transmission Tariff ("OATT") typically utilize the network integration transmission service of the network customer that is purchasing their output. It is implied that qualifying facilities connecting under the North Carolina Interconnection Procedures ("NCIP") are similarly utilizing the utility network integration service, since they are selling exclusively to the utility.

Prior to interconnection, DG are studied by transmission planners for impacts to the transmission system in a study that includes both transmission- and distribution-connected projects. As DG penetration levels have increased, it has been recognized that DG can negatively impact the transmission system. One of the features of the Queue Reform is to more efficiently allocate and assign transmission upgrades to distributed generators through cluster study. These network upgrades are direct-assigned to the project and paid as Contribution in Aid of Construction. Furthermore, the North Carolina Interconnection Agreement ("IA") Section 5.2 states that "*the actual cost of the Network Upgrades, including overheads, on-going operations, maintenance, repair, and replacement shall be borne by the Interconnection Customer*".

Distribution Demand - Substations

Distribution substations costs are allocated entirely based on non-coincident peak. Since distributed generators are not assigned demand-based charges for distribution system access, this is a functional area that requires scrutiny. Distributed generators utilize distribution substations in several cases:

- **Voltage Regulation:** Voltage regulators operate to control voltage swings caused by distributed generation. The NCSU study indicates that at lower DG penetrations regulator operations and transmission to distribution ("t-d") transformer demand can be reduced. At higher DG penetrations, regulator operations are increased. This indicates an inflection point in DG penetration where there is demand-related cost causation. The figure below is taken from the NCSU study where distributed generation grows from zero to 150% of peak load on the feeder over 10 years.



Increasing PV penetrations increases LTC operations and tapers off after year 5

Backflow: At higher penetrations, the t-d transformer is used as a step-up transformer for the distributed generators to backflow onto the transmission system. The NCSU Study observes that even transformer banks experiencing large amounts of backflow are still reducing the absolute substation transformer loading. The criterion used in the cost estimation below looks at substations where the t-d transformer backflow exceeds 50% of the estimated solar output connected downstream of that transformer bank. This criterion is proposed as establishing a causal pattern of use at the substation by the DG and can also be applied in determining avoided line loss benefits for large qualifying facilities connecting to the distribution system.

$$\frac{\sum Substation\ Backflow}{Capacity\ Factor\ \%\ x\ DER\ Capacity\ x\ 8760} \geq 50\%$$

In 2019, there were 4 transformer banks with a total of 40MWac connected that met this criterion in DEP-NC.

- **Distribution Control Center:** Distributed generators are considered in all aspects of load dispatch and control including feeder optimization models, capacity planning, and switching operations. In NC CoS studies, the distribution substation function includes Federal Energy Regulatory Commission ("FERC") Account 581 for load dispatch and system control expense. This is a functional area where the impact of distributed generation is generally accepted to be increasing. Below is the list of FERC Account 581 items referenced in the Code of Federal Regulations ("CFR") that are directly impacted by distributed generators.

- Directing switching
- Arranging and controlling clearances for construction, maintenance, test and emergency purposes
- Controlling system voltages
- Communication service provided for system control purposes

- **Anti-Islanding:** Relays and communications equipment are deployed at the substation to enable anti-islanding protection for the distributed generator. These are direct assigned to interconnection customers as network upgrades. While NCIA Section 5.2 provides for the assignment of ongoing costs of these upgrades, there is not currently a recovery mechanism for the subsequent operating expense. These types of upgrades have predominately been assigned in DEC to sites >1 MW.

Distribution Demand - Primary

Typically, 60% of distribution primary costs are allocated on a per-customer basis using the minimum system framework. The table below shows the distribution primary plant breakdown in DEP's year 2018 per books cost of service at a total system level (including NC retail and SC retail).

Distribution Primary	Plant ($)
PRIMARY POLES - CUSTOMER	436,382,960
PRIMARY CONDUCTOR - CUSTOMER	689,904,332
U/G LINES - PRIMARY CUSTOMER	471,336,487

PRIMARY POLES - DEMAND	159,718,699
PRIMARY CONDUCTOR - DEMAND	245,492,291
U/G LINES - PRIMARY DEMAND	436,334,267

Distribution Primary - Customer	1,597,623,778
Distribution Primary - Demand	841,545,257
Minimum System Allocation	**65%**

Distributed generators are currently paying per-customer charges through the Seller/Administrative Charge on their Purchase Power Agreement ("PPA") and the Customer/Basic Facilities Charge on their General Service retail rate schedule. Distributed generators also pay Extra Facilities charges, per Service Regulations, on the interconnection facilities required to connect them to the utility system. This includes a system-level operations and maintenance ("O&M") rate to cover the ongoing cost of these facilities. The table below details the various applicable charges.

Monthly Charges Applicable to Qualifying Facilities, Effective 1/1/2021

Utility	Schedule	Charge	SC	NC
DEP	PP	Monthly Seller Charge	$8.05	$23.06
DEC	PP	Administrative Charge	$11.07	$19.91

DEP	SGS	Customer Charge	$12.34	$21.00
DEC	SGS	Basic Facilities Charge	$11.70	$19.39
DEC/DEP	Service Regulations	Extra Facilities	1% of installed cost	1% of installed cost

Interconnection customers may be assigned cost responsibility for distribution upgrades per article 4.1 of the NC Interconnection Agreement. This includes responsibility for ongoing costs. From a distribution primary perspective, these upgrades are often reconductoring projects, where larger gauge conductor is installed, and structures are updated. These upgrades potentially benefit retail customers through increased capacity on the circuit, as well as increased reliability due to lower failure rates on the updated structures.

The Company maintains Method-of-Service Guidelines that are primarily intended to mitigate DG impacts to reliability, power quality, and cost of service. For example, one of these guidelines states that distributed generators must connect "to the first regulated zone of distribution circuits (substation bus regulation or circuit exit regulation)[1]". This guideline particularly limits distribution primary impacts, because they are connecting in the stiffest part of the circuit closest to the substation. If more and larger projects were to be allowed to connect outside of the primary regulation zone, these cost of service impacts would be of greater concern.

The NCSU Study also indicates that distributed generators can provide positive cost of service impacts to the system by avoiding or deferring distribution primary upgrades. These impacts were discussed at length in the Commission's April 15, 2020 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities.

Distribution Demand - Line Transformers

While NCIP Section 3.2.1 Fast Track screens limit cost of service impacts in several ways, the 3.2.1.8 screen specifically addresses distribution line transformer function impacts.

> *3.2.1.8 If the proposed Generating Facility is to be interconnected on a single-phase shared secondary, the aggregate Generating Facility capacity on the shared secondary, including the proposed Generating Facility, shall not exceed 65% of the transformer nameplate rating.*

Step-up transformers for larger distributed generators are typically located on the customer side of the point-of-interconnection and are paid for and maintained by the customer.

Distribution Demand - Secondary

Distribution secondary impacts are primarily mitigated by NCIP Section 3.2.1 Fast Track screens as discussed above.

Customer

Sell-all distributed generators are direct-assigned capital costs for their meters. Otherwise meter capital and O&M costs are recovered through Customer/Basic Facilities

[1] method-of-service-guidelines-20171013.pdf (duke-energy.com)

Charges shown above. Sell-all customers also pay a complex billing fee for supporting purchased power accounts. This is included in the Seller/Administrative Charges also shown above.

Cost Estimation

Section 8-Computational and Engineering Effort for the Case Study of the NCSU Case Studies indicates that system-wide characterization of the incremental costs described above and in their study are not "practically manageable" given the number of nodes and required sensitivities. Based on the above discussion, on the NCSU Study Team's review of other methodologies, and by the NCSU Study Team's results of equipment usage from model circuits, the following functional areas are reviewed for cost estimation. The estimation method here is meant to align with existing COS classification.

1. DEC Operating Expenses for Fiber, Relay, and Communications Equipment

   Inputs:
   Monthly O&M Rate (%) *O&M-only component of DEC-NC monthly Extra Facilities charge*
   DEC DTT Projects (#) *Estimated count of connected DEC projects requiring protection upgrades*
   Installed Cost ($) *Estimated average installed cost for protection upgrades*

   Annual Cost ($) *= 12 * Monthly O&M Rate * DEC DTT Projects * Installed Cost*
   *= 12 * 0.3% * 23 * $240k*
   = $132,000

2. DEP Share of Distribution Load Dispatch and System Control

   Inputs:
   Distributed Generation Capacity (MWac) *Distribution sell-all projects connected in DEP-NC*
   Total Retail NCP (MW) *Total DEP-NC retail non-coincident peak ("NCP") taking service at primary and secondary distribution voltages*
   O&M Load Dispatch ($) *FERC Account 581 items from 2018 DEP-NC CoS Study, detailed above*

   DEP NC DER Ratio (%) *= Distributed Generation Capacity /*
   (Distributed Generation Capacity + Total NC Retail NCP)
   = 1,771 / (1,771 + 16,676)
   = 9.6%

   Annual Cost ($) *= DEP NC DER Ratio * NC retail O&M Load Dispatch*
   *= 9.6% * $4.1M*
   = $389,746

   Note: Similar to Schedule 1 Service in the OATT

3. DEP Share of Distribution Substation Expenses for Backflow Substations

   Inputs:
   DG Capacity @ Backflow Banks (MWac) *DEP-NC installed distribution sell-all capacity on substation transformer banks observed to be backflowing (Backflow >50% of Est. PV Energy-2019)*
   Total Retail NCP (MW) *Total DEP-NC retail non-coincident peak taking service at primary and secondary distribution voltages*

   DEP DER Ratio @ Backflow Substations (%) *= DG Capacity @ Backflow Banks /*

(DG Capacity @ Backflow Banks + Total Retail NCP)
= 40 / (40 + 16,676)
= .23%

Annual Cost ($) *= DEP DER Ratio @ Backflow Substations * Facilities Charge * Substation Plant*
*= .23% * 12% * $767M*
= $220,224

Options for Recovery

As part of the required study, the Commission requested that Duke share various options for recovery of these costs. The following section outlines those options and various considerations for each.

It is clear that changes are required to the design, operation and maintenance of the electric grid in order to integrate with and efficiently operate a significant amount of DG. There is a fundamental question of whether these changes and their associated costs are simply part of the evolution of technology, or whether they are detrimental to customers and therefore should be borne by distributed generators. While the cost-causation of certain facilities and functions is clearly attributable to individual generators, there may be DG-related costs that are appropriate to consider as normal O&M of the grid. This argument draws a distinction between incremental costs caused by DG versus base costs required to operate and maintain a distribution system with material DG capacity, in light of the benefits provided to all customers.

1. **Base Rates in Embedded Cost of Service Study (Distribution Demand)**: Distribution Substation Expenses for Backflow Substations could be allocated with other distribution substation costs in the cost of service for recovery through base rates. For the reasons described above, it is appropriate to consider the expenses related to backflow substations as base costs in the O&M of a distribution system in light of the benefits provided to all customers.

2. **Monthly Facilities Charge**: The Monthly Facilities Charge is based on IA Section 6.1.3 which states "[t]he Utility shall also bill the Interconnection Customer for the costs associated with operating, maintaining, repairing and replacing the Utility's System Upgrades" and "[t]he Utility shall bill the Interconnection Customer for the costs of providing the Utility's Interconnection Facilities including the costs for on-going operations, maintenance, repair and replacement of the Utility's Interconnection Facilities under a Utility rate schedule, tariff, rider or service regulation providing for extra facilities or additional facilities charges."

   The Extra Facilities provision of each Utility's Service Regulations would apply to Interconnection Facilities costs. The standard payment method for Extra Facilities is a monthly charge of 1.0% of the installed cost of the applicable facilities.

   Operating Expenses for Fiber, Relay, and Communications Equipment are clearly covered within the scope of IA Section 6.1.3. A monthly charge could be calculated based on the estimated cost of protection upgrades. This mechanism would provide the flexibility to assign these costs specifically to the distributed generators that require such upgrades, and thus fulfill the rate design principle of cost causation.

3. **Seller/Administrative Charge**: The Seller Charge (DEP) or Administrative Charge (DEC) is a fixed, monthly charge included in Purchased Power Schedule PP intended to recover general and administrative costs.

   Distribution Load Dispatch and System Control costs could be incorporated into the Seller/Administrative Charge. These are classified as customer costs (i.e. incurred based on the number of distribution generators) and could appropriately be recovered through a fixed charge. This would align with how customer costs are typically recovered through rate design.

   Distribution Substation Expenses for Backflow Substations are O&M costs resulting from distribution substations functioning as t-d step-up transformers due to excess generation from distributed generators. While backflow conditions can be triggered by individual generators, these costs should be allocated to all distribution-connected generators (or to applicable customer classes via Base Rates as described previously) because of the variability of the backflow condition and because of the limited ability for a customer generator to avoid or mitigate such impact. As such, these costs could also be incorporated into the Seller/Administrative Charge.

   The Seller/Administrative Charge could be split into two rates (applicable to distribution- and transmission-connected generators) in order to allocate the above distribution-specific costs appropriately.

4. **Distribution Facilities Charge (Proposed)**: A new demand-based Distribution Facilities Charge ($/MW) could be proposed as a separate charge for Power Purchase Agreements.

   Distribution Substation Expenses for Backflow Substations are driven by the capacity of connected DG, given that the frequency and extent of backflow is tied to the peak power delivered by the DG. Therefore, a Distribution Facilities Charge based on nameplate capacity would better reflect cost-causation than a customer charge such as the Seller/Administrative Charge.

Coordination with ISOP

In the September 5, 2019 *Order Granting Waiver* mentioned above, the Commission specifically requested that the Companies' ISOP capabilities "inform and coordinate" with this effort. The following ISOP tools were used in the creation of the case studies and cost estimation:

- *Morecast* – The feeder-level load growth forecast that was assumed for the case studies was drawn from the pre-production instance of this tool.
- *ISOP Data System* – The actual feeder and transformer bank loads used in the cost estimation and case studies were pulled from the ISOP database and reporting layer.
- *Advanced Distribution Planning* – circuit models generated by the ADP project team using the pre-production version of these tools were used in the case studies.

The ISOP planning coordinators also provided valuable insight and review in all phases of this effort.

Framework for Estimating DG Cost of Service

Mesut Baran Wenyuan Tang
Keith Dsouza Rishab Gupta
NC State University

Preface

This is the first interim report of a study conducted by a research team at NC State university which aims at development of a methodology for assessing the cost of service components associated with Distributed Generation (DG) connected to a utility distribution system. The study was undertaken in support of the North Carolina Utilities Commission's June 14, 2019 order requiring testimony characterizing the benefits that distributed generators are receiving from the Utility's Systems, estimating their share of the related costs, and providing options for fully recovering those costs from distributed generators.

I. Introduction

The rapid penetration of distributed energy resources is creating challenges to the cost-of-service estimation. On November 19, 2018, Public Staff witness Lucas testified that as more and more distributed generation (DG) capacity is interconnected, the grid's ability to accommodate additional, future capacity without requiring significant investments in additional facilities is being diminished. These additional facilities also incur additional grid operation and maintenance (O&M) expenses. However, the interconnection fees paid by DGs do not include costs associated with future grid investments or ongoing operation and maintenance of the grid. On June 14, 2019, the Commission issued an order, noting that Section 6.1.3 of the Interconnection Agreement that is part of the NC Interconnection Standard states as follows: "The Utility shall also bill the Interconnection Customer for the costs associated with operating, maintaining, repairing and replacing the Utility's System Upgrades." The Commission especially requires testimony characterizing the benefits that distributed generators are receiving from the Utility's Systems, estimating their share of the related costs, and providing options for fully recovering those costs from distributed generators. Therefore, in accordance with the Commission's order, Duke Energy has teamed up with NC State University and Advanced Energy to perform a study to determine the cost-of-service impacts of DG.

The main challenge in integrating a DG resource – such as a PV system – into a distribution system arises mainly due to the fact that distribution feeders are designed and operated based on the assumption that all loads are passive, i.e., there is no active generation source in the system. Hence, accommodating DG may require the enhancement and/or revision of distribution system control, O&M, and even planning activities in order to continue to provide reliable service to the customers. The extent of modification in these activities depends on the DG "penetration level" (which mainly depends on its type, size, and location).

Utilities recover the cost associated with upgrades they deem to be necessary in order to integrate a large scale DG (e.g., PV farms 1 MW or greater) into the grid. However, the long term O&M

costs the utility incurs due to the DG impact on the system is currently not recovered from DG owners. This study will focus on these O&M and planning costs, and develop a methodology for their quantification. The study will focus only on Duke Energy's distribution system in NC and consider the integration of small scale PV systems (smaller than 1 MW) to distribution systems. These PV systems will be referred to as DG facilities, as the proposed methodology can be adopted for other types of DG.

II. Methodology

Before developing a study methodology, a facilitated stakeholder meeting of approximately 30 people was held on December 6, 2019. The event was organized by Advanced Energy. The goal of this initial meeting was to gather questions and comments from stakeholders to inform the cost of service study methodology. Some common themes from the input received include: overall scope and objective clarification for study, addressing the diversity of DG systems, including ancillary services used by and provided by DG, study how other states have handled cost allocation of DG, take into account that NC has a high penetration of distribution connected DG which poses novel challenges that may not already be addressed in previous studies. The input received from stakeholders during the initial meeting was considered when developing the study methodology outlined in this document.

In searching for a methodology to adopt, we noticed that most of the cost-of-service studies follow the following steps:

Step 1: Identify main cost and benefit components

Step 2: Develop methods to quantify and monetize these components

We have adopted this approach for this study. Next, these steps are elaborated to provide more details about the proposed methodology.

II.1 Cost of Service Components

In this step, the goal is to identify the main impacts of DG on distribution system operation and determine the main mitigation measures that need to be taken in order to accommodate DG on the distribution system. These impacts and mitigation measures will help us identify and make an assessment on the main cost-benefit components.

To achieve this goal, two main activities have been undertaken. First, a review of recently conducted studies has been performed, as within the last few years, many public utility commissions across the US have sponsored studies in order to determine better ways to assess the cost and benefit components DG imposes on power systems. The second activity involved meeting with engineering teams from the distribution system operation and planning departments at Duke Energy, in order to get feedback on actual field experience on this topic.

II.1.1 Review of Recent Studies

We have reviewed some of the recently conducted "DG valuation" studies. These studies mainly focus on the avoided energy and capacity components at the generation and transmission level. We focused on the studies which considered some of the cost-benefit components at the distribution level. *Table I* contains a list of all the studies reviewed along with some key highlights from those studies.

The main findings from these studies are as follows:

a. In most of the studies, the basic approach involves determining avoided cost/benefit: First, create a baseline with the existing and planned system without DG. The next step is to estimate the additional system upgrades needed in order to accommodate the projected DG in the system. The cost-benefits associated with estimated upgrades provide an estimate of the costs or benefits for the projected amount of DG that was considered. This approach does not explicitly consider the improvements that have been made to the system as a result of the system integration studies that the utility conducts for farms.

b. Some of the studies mainly focus on small-scale PV systems, while others consider both small-scale and large-scale PV systems.

c. *Table I* summarizes the main cost/benefit components considered in all the studies reviewed. As the table indicates, the most common categories considered are related to distribution capacity deferral and line loss reduction, followed by power quality and O&M issues. Distribution capacity deferral depends on the level of deployment of DG. Although this potential benefit has been identified by many, most studies do not conduct comprehensive analyses, nor do they propose detailed methodologies to quantify this category. Some studies do not consider this category due to its negligible value (such as Georgia Power). Power quality and O&M issues were also highlighted in some of these studies, but most studies considered these categories as placeholders. Some further stated that the means to quantify these benefits are not well established.

d. The general consensus from the literature review is that the value of each category is extremely case specific. Also, the methods used to quantify each component varies considerably.

Table I: Cost/Benefit Categories Considered in Recent DG Valuation Studies

Categories	Capacity Deferral		Losses		Power Quality		Equipment Life		O&M Costs		Reliability		Ancillary Services		Interconnection Costs		Administrative Costs		Stranded Assets		Distributed/ Utility-Scale Solar
Studies	**C**	**B**	**C**	**B**	**C**	**B**	**C**	**B**	**C**	**B**	**C**	**B**	**C**	**B**	**C**	**B**	**C**	**B**	**C**	**B**	
Georgia, Georgia Power Company [1]				Q	P				Q				Q				P		Q		Both
Tennessee, TVA and EPRI [2]	Q	Q		Q	Q				Q								Q				Both
Maryland, Daymark [3]		Q			Q	Q		Q				P			Q						Both
Austin, Clean Power Research [4]		Q								Q											Both
Arizona, R.W. Beck [5]		Q		Q	Q			Q													Dist
Michigan, NREL [6]		Q		Q																	Both
NJ/PA, Clean Power Research [7]		Q		Q																	Both
San Antonio, Clean Power Research [8]		Q		Q																	Dist
Arizona, SAIC [9]		NQ		Q	Q			Q			P	P									Both
Colorado, Xcel Energy Services [10]		Q	Q	NQ		Q								Q							Dist
Arizona, Crossborder Energy [11]		Q		Q																	Both
North Carolina, Crossborder Energy [12]		Q		Q																	Both
Austin, Clean Power Research [13]		Q		Q																	Both
Utah, Clean Power Research [14]		Q		Q																	Both
Minnesota, Clean Power Research [15]		Q		Q									Q		P						Dist
Nevada, E3 [16]		NQ		Q																	Both
Mississippi, Synapse Energy [17]		Q		Q								P	Q		P		P		P		Dist
Vermont, Public Service Dept [18]		Q		Q													P				Dist
Maine, Clean Power Research [19]		P											P		Q						Dist
Massachusetts, Acadia Center [20]		Q		Q																	Dist
Louisiana, Acadian Consultancy Group [21]		Q		Q																	Both
South Carolina, E3 [22]		Q		Q									Q	Q	P		P				Both
Arizona, Crossborder Energy [23]				Q					Q				Q		Q		Q				Both
Nevada, E3 [24]		Q		Q					Q						Q		Q				Dist
DC, Synapse Energy Economics [25]		Q		Q								Q	Q	Q							Dist
Arkansas, Crossborder Energy [26]		Q		Q							P	P									Dist
Montana, Northwest [27]		Q		Q		Q				Q		P	P				Q				Both
Louisiana, LSU [28]		Q	Q	Q	Q		Q								Q		Q				Both

C – Cost
B – Benefit
Ancillary Services only considers reactive power/voltage support

Considered and Quantified	(green)
Considered but not Quantified	(blue)
Placeholder	(orange)

Among these studies summarized above, we further identified four of the most recent studies which have provided more detail on the distribution level cost-benefit components. A more detailed summary of these studies are provided next.

1.“A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia - 2019” [1]

This study adopts a methodology for determining the cost and benefits of renewable resources on Southern Company’s system. This report was part of the docket filed to the Public Service Commission by Southern Company.

The distribution level components considered in the study include:

a. *Avoided System Losses*: DG connected to a feeder affects the power loss on the feeder. Two methods are considered to quantify this component. The study points out that this component is case specific.

b. *Distribution Operation Cost*: Included as a placeholder (component not quantified in the report), but the following issues are identified:

   - *Conservation Voltage Reduction (CVR) program*: CVR may be impacted as DG increases the voltage profile on the feeder.
   - *Voltage Regulator Operation*: Voltage swings causes the VRs to operate more frequently, thereby increasing the required maintenance or shortening the equipment life.
   - *Automatic Fault Isolation and Restoration (FLISR) Schemes*: DG will mask the actual load. This may result in limiting the system’s ability to restore service or in overloading adjacent circuits when restoration is attempted.

c. *Ancillary Services*: This study highlights the potential of smart inverters providing reactive power and voltage support. However, at this time, there is no formal arrangement for DG resources to provide such a service. Hence, this component is considered as a placeholder.

d. *Deferred Distribution Investment*: Currently, Southern Company requires that all distributed resources cease energizing the distribution system upon occurrence of a fault on the distribution system. Hence, the study concludes that there is no positive impact of DG on the distribution system’s capital investments. Additionally, the study notes that the intermittent nature of these facilities does not help in deferring these investments.

e. *Program and Administrative Costs*: There are costs associated with implementing a renewable resource program. These include interconnection costs, program costs, administrative costs, and accounting costs. This component is included as a placeholder.

2. “Distributed Generation – Integrated Value -2015” [2]

In this study, TVA along with EPRI and a stakeholders group developed a comprehensive methodology to assess both the benefits and costs associated with DG. The method adopts the *Integrated Grid* framework proposed by EPRI, and uses the concept of *Feeder Hosting*

Capacity to assess the DG impact on a distribution system. The main components considered include the following:

a. *Distribution System Impacts*

- *Distribution Capacity*: DG has the potential to offset/defer the need to upgrade capacity. The extent of this benefit depends on how much DG generation coincides with the load peak. The reduction in peak load levels has the added benefit of extending equipment life – lower peaks reduce heating and related degradation. However, no method was proposed to quantify this component.
- *Voltage Issues*: An increase in DG penetration can result in voltage regulation issues. If DG penetration rises above the feeder's hosting capacity, then mitigation strategies may need to be considered to address the voltage related issues.
- *Protection:* Protection coordination issues can be caused by DG especially at higher penetrations. These include nuisance fuse blowing, mis-operation of breakers/reclosers, increased short-circuit current levels, and sympathetic tripping. Mitigation of these issues may require engineering effort, capital investment or a combination of both.

b. *Distribution Net Marginal Losses*:

- *Power Losses*: DG can reduce losses on a feeder. The extent of loss reduction depends on the feeder configuration, load distribution and profile, as well as the DG penetration levels. As DG penetration increases, there can be an increase in losses as well.
- *Energy Conservation*: The increase in feeder voltage due to DG can have an unintended consequence of increasing energy consumption. This can interfere with the ability of CVR equipment to bring down voltages to reduced levels, affecting the return on investment of these projects.

3. "Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland - 2016" [3]

This study was commissioned by the Public Service Commission of Maryland to ensure that Maryland's electric distribution systems were customer-centered, affordable, reliable, and environmentally sustainable. The study was conducted by Daymark Energy Advisors who published the report in 2018. The study looks at different types of solar installations such as rooftop solar, small and large commercial installations, and utility scale solar. The study focuses on feeder level hosting capacity and circuit specific operational needs. This in turn will provide location based integration cost estimates to the developers. The components considered include the following:

a. *Deferral of Distribution Investment*: Whether solar provides any deferral in distribution system capacity and related investments.

Integrating PV systems on a feeder may contribute towards deferring/eliminating the need to perform system upgrades that would be required due to load growth. To quantify this contribution study proposes calculating the capacity factor related to the projects. This study suggested that projects that required lower system upgrades offered better value for the same net capacity of DG.

The study also points out that since the interconnection of large PV systems to the distribution network may require system upgrades on a case by case basis, these upgrades may also provide benefits to the system operation. Any costs associated with the project are borne by the developer; however, the benefits – that are part of the interconnection requirement but may also be shared by other customers in the future – are retained by the utility.

b. *Reduction in Losses, and Wear and Tear*: Whether solar offsets peak loading which in turn reduces wear and tear on equipment.

Strategic placement of solar projects can help reduce losses due to reducing/offsetting the system peak demand and improve voltage profiles. The study also claims that reduction in voltage variation will reduce the operation of mechanically switched voltage regulation equipment; thus, increasing its life. However, improper deployment of solar can exacerbate this issue, the same is true for avoided system losses; they can be either a cost or a benefit.

c. *Avoided Distribution Outages*: Whether solar reduces outages associated with overloaded facilities during peak load.

In Maryland, power is delivered to rural areas by lengthy distribution feeders often hundreds of miles long. Strategic placement of solar can help avoid overloads and related outages. This study looks at historical outage events and suggests that strategically placing solar could potentially address some of the equipment and load related outage events. However, no value was attributed to this component.

d. *Benefits of Controllable Solar*: Whether advanced technology, if present, can provide services such as managing voltage regulation and flicker, and ride-through capabilities. This component was pointed out as a potential benefit but not quantified and included.

4. "Marginal Cost of Service Study – Con Edison, 2018" [29]

This study was performed by the Brattle Group, Inc. and EnerNex LLC for the Consolidated Edison Company of New York, Inc. to determine the Marginal Cost (MC) based cost of service on a distribution feeder or distribution network. The study considers only the load growth on a distribution feeder, and uses the system upgrades needed to accommodate this load growth (the wires alternative) to calculate the MC. MC (in $/kW) for a feeder is the investment needed to accommodate incremental load growth on that feeder. MC is calculated for each of the cost centers (five cost centers are considered). Since the system upgrades are done periodically, MC is annualized to provide MC on a yearly basis over the planning horizon. Study points out that this MC provides a baseline for comparison to non-wires solutions such as DER (Distributed Energy Resources).

This study then calculates MCs for all of the 84 Load Areas within parts of Con Edison service area (Orange & Rockland) using projected costs and loads for the ten-year period of 2018 through 2027. Figure 1 below shows the annualized MC on a cost center basis.

Figure 1: Con Edison Marginal Costs on a Cost Center basis [29]

The study also aggregates the 84 load areas into six aggregated areas which reflect the common characteristics of the load areas aggregated. A metric called Locational System Relief Value (LSRV) is calculated for each area. The LSRV reflects the average MC of the areas being aggregated and it can be used to evaluate potential locational benefit of a DER (or any measure that reduce load growth) at the distribution level.

II.1.2 Feedback from Duke Engineering Teams

This activity involved having meetings with Duke Energy engineers from the distribution system operation, and planning departments. These meetings allowed us to get feedback on the actual impact that DG (large-scale PV farms) have on Duke Energy's distribution systems and the mitigation measures that have been taken in the recent years. The minutes of these meetings are provided as *Exhibit I* and *II* in the appendix. As these Exhibits will show, the feedback based on field experience has provided more detailed and comprehensive cost components, some of which are not captured in the large scale studies reviewed. A summary along with the highlights from these two meetings are given below:

i) Impact on Equipment

- *Substation Voltage Regulators (VR)/Load Tap Changers (LTC)*: PVs cause a steep increase in operation of these devices due to ramping and intermittency of its output. This increases the wear and tear on these devices.
- *Capacitor Banks*: Solar inverters operate at unity power factor; any reactive power drawn by the load needs to be provided externally (substation or CAP banks). A sudden change in PV output may cause switching of capacitor banks, and thus increasing the wear and tear that they are subjected to.
- *Fault Indicators/Detectors*: These devices require a certain amount of current to flow to charge their batteries. With PV in the system, they need to use their batteries more often, and hence, their batteries need to be replaced more frequently.
- *Mitigation using Dynamic VAR Compensator (DVAR)*: Duke Energy is considering deployment of DVARs to mitigate harmonics and voltage issues on feeders with high PV

penetration. Analysis of one pilot DVAR project indicated that they also help reduce regulator operations considerably.

ii) Impact on O&M

- *Increase service of substation LTC/VR*: The increase in operations of LTC/VRs due to ramping and intermittency of PV farms made it necessary to increase the maintenance frequency of these devices.
- *LVR operation*: The control mode for some VRs needs to be changed manually depending on the direction of power flow. This problem is aggravated by intermittent and varying PV.
- *Power Quality (PQ)*: Voltage/Power quality issues may arise after new DG projects are interconnected to the grid. These issues are investigated, and mitigation measures are taken by the PQ team. DEP has experienced power quality problems when feeders contain large PV farms. Some of the issues experienced include: capacitor bank cycling, more severe voltage sag following a PV recloser operation, temporary overvoltage that can cause equipment degradation/failure, and high frequency harmonics by PV inverters causing PQ events on sensitive customer equipment *[Exhibit I]*.
- *Transformer Inrush*: During transformer energization at a large PV farm, the large inrush causes voltage sag on the feeder and this causes other equipment on the feeder (DVAR, controls etc.) to mis-operate. In such cases mitigation measures are needed.

iii) Impact on System Monitoring and Engineering Effort

- *Load Masking*: Accurate estimation of native load is important for system capacity expansion planning. The presence of DG adds complexity to this process, because not all DGs are monitored (real-time), even some of the large PV farms. This requires additional effort to extract the native load data on a feeder basis from the net load measured at the substation.
- *Self-Optimizing Grid (SOG)*: SOG is one of the new tools in Duke Energy's arsenal to ensure reliability and resiliency. Circuits are divided into segments that can be reconfigured in the event of an outage, reducing downtime. However, the presence of DG affects the functioning of this program. DGs may need to be taken offline before circuits can be safely switched.
- *DSDR (Distribution System Demand Response)*: DSDR is used to either reduce energy or power demand by lowering the voltage. It is difficult to optimize DSDR when there is a variable source of energy such as a PV farm on the distribution system. Hence, the DSDR will not provide the same level of benefit as it does with no DG.
- *Software Upgrades to Handle VR Control Modes*: The DMS Software needs to be upgraded to take into account the proper mode of operation of the VRs. Also, the DMS needs additional real time data to monitor and verify their control mode.

II.1.3 Proposed Cost-of-Service Components

The studies reviewed and feedbacks from the stakeholders meeting and the engineers from Duke Energy provided a detailed list of issues related to DG impact on distribution system operation and planning. Based on these, we propose to consider the following components in this study:

C.1 Capacity Benefits

As pointed out in the summaries, many studies considered the potential of DG reducing peak load, and hence, increase system capacity. However, many utilities, including Duke Energy, point out that system capacity expansions are mainly determined by native load. Distributed small scale PV system have the potential to defer/reduce future capacity expansions that may be needed as the native load grows.

C.2 Power Loss Reduction

Most of the studies consider the potential of DER reducing power loss on a distribution circuit. The amount of reduction is highly case specific and high penetration scenarios may even result in an increase in power loss. A good screening tool is needed to effectively estimate this component in order to minimize the engineering effort needed to calculate it.

C.3 Feeder Equipment Maintenance and Lifetime

As pointed out in the summaries, high DG may affect feeder equipment, shortening their lifetime and/or cause damage:

a. *Substation Equipment*: The increase in tap operations of LTCs/LVRs due to DG's intermittency reduces their lifetime and requires more frequent maintenance of these equipment. The lifetime of a substation transformer may also be reduced due to slower protection subjecting the transformer to longer fault currents.

b. *Capacitor Cycling*: DG intermittency may cause capacitor banks to operate more frequently and this requires more frequent inspection and maintenance of these devices.

c. *New Equipment*: Increasing levels of DG penetration may necessitate installation of new mitigation devices, such as DVAR.

C.4 System Operation

Main system operation issues to be considered will include:

a. *System Monitoring and Control:*

- *Volt-VAR control (VVC)*: Depending on the DG penetration level, the VVC control schemes employed may need to be revised and upgraded. Duke Energy has a VVC program (DSDR); it is also part of the Self Optimizing Grid (SOG) program. Some of the specific issues that will be considered are elaborated in *[Exhibit I] and [3]*.
- *Monitoring*: Feeders with high DER penetration may need more detailed and frequent monitoring to ensure that no major voltage violations or overload conditions occur on the feeder. This issue may necessitate the upgradation and/or adoption of new *Distributed Energy Management Systems (DMS) – [Exhibit I] and [3]*. These issues have an impact on both system operation as well as planning efforts.

b. *Outage Management:* When a feeder experiences an outage, the extent of the outage must be identified and proper action – like feeder reconfiguration – needs to be taken. The presence of DER in a circuit affects this outage management process, making it more challenging. Duke Energy has adopted SOG to improve their management response. Some issues related to the interference of DER are presented in *[Exhibit I]*. The extra engineering and operation efforts involved in such outage management events is another component that needs to be considered.

C.5 Operation Planning

Duke Energy reviews their distribution systems on a yearly basis to determine upgrades. Upgrades on a feeder are determined by the peak native load (on that feeder). Determining the native load of a feeder takes more engineering effort especially when there is limited data available from DG resources on the feeder i.e. not all resources are monitored – *[Exhibit I]*.

II.3 Quantifying & Monetizing the Cost-of-Service Components

This second step focuses on the development of methods to quantify the cost-of-service components identified above. These quantities will then be used to monetize each component.

As indicated, the study will focus on the expected small scale PV growth on Duke Energy distribution system. Since the growth will occur gradually over the next 5-10 years, we will consider a short-term planning period of five years. We will simulate the expected PV growth on a selected set of distribution feeders and use these results to quantify the proposed cost-of-service components on a distribution feeder basis. The cost components will then be allocated to the Service Centers Duke Energy uses: i) Substation, ii) Distribution Feeder, iii) System Operation/

Administration.

Given that the system upgrades will be done as needed in every couple of years, we propose to annualize these new upgrade deferrals and thus get an estimate of total cost estimate on a yearly basis over the planned period of 5 years. Figure 1 illustrates this final cost estimate.

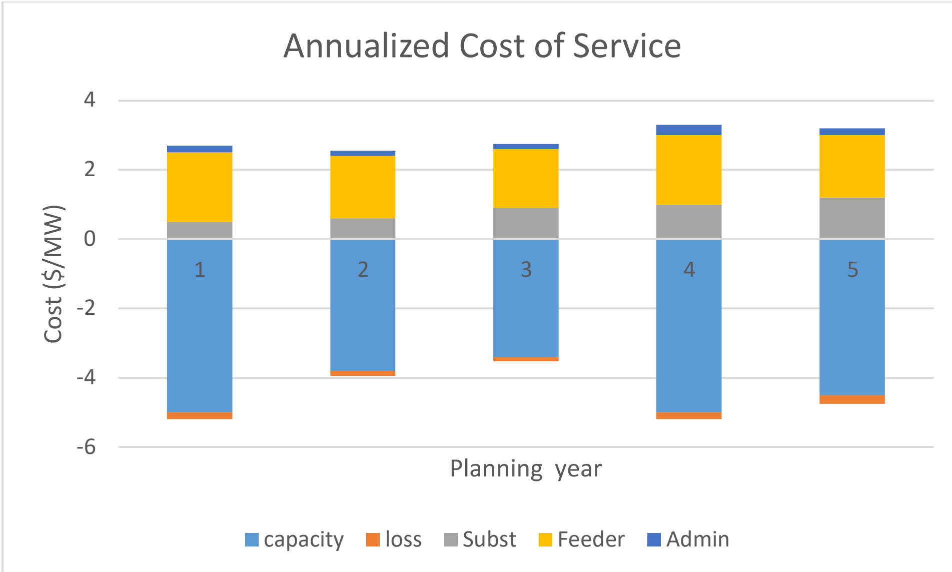


Figure 1: Annualized Cost of Service for DG on a Feeder

The following steps will be pursued to estimate the cost-of-service components:

1. *Literature Search on Methods*: Conduct a literature search to identify existing methods that have been adopted or proposed for quantifying the components identified.
2. *Feedback from Duke Energy's Engineers*: Meetings with Duke Energy's engineers will be arranged to get feedback about the methods used in practice, and the availability of the data which is needed to quantify a given component.
3. *Case Studies*: Case studies will be conducted to quantify many of the components (see below for more details). This is an effective approach as it involves performing detailed simulations on actual feeders.
4. *Cost Estimation*: The components quantified above will be monetized to estimate the total cost of service for a given distribution system. The project team will work with Duke Engineers to get a cost estimate for equipment, labor, and engineering services, and use these estimates to monetize the components.

As indicated above, simulation based case studies will be the main tool that will be used to estimate the main cost components. However, there are some components, such as C4: System Monitoring, and C6: Operation Planning, which are difficult to get estimation through simulation. Hence, for these components, we are planning to consult with the field engineers who are familiar with these issues and use historical data to estimate these components. These two approaches are elaborated below.

II.3.1 *Case Studies:*

Establishing proper cases to be simulated is a challenging task. A set of representative feeders with expected DG connection will be used in the study. Duke Energy will select and provide data for these feeders. In this study the focus will be the integration of small scale of PV systems to distribution feeders, as Duke Energy expects that most of the new growth in third party PV development will be of this type.

Noting that the impacts identified in *Step I* occur on different timescales, we can broadly group the simulations into the following main categories:

1. *System Operation*

The impacts of DG on a system's operation will be studied by means of steady-state power flow analysis based simulations. The steady-state analysis will be conducted on the selected representative feeders and will involve the following steps:

i) The analysis will consider the system under normal conditions with hourly PV output and load, and will use the commercial software programs CYME and OpenDSS for the analysis.
ii) To capture different operating conditions on a feeder, separate load profiles for weekdays and weekends, summer and winter seasons will be simulated. Also, typical PV output will be considered based on the location of the feeder. Duke Energy will provide the load profile data, and publicly available data (from NREL) will be used to estimate the PV profiles.
iii) On a given feeder, two sets of simulations will be performed. The first study will simulate the current feeder and its planned growth within the planning horizon of 5 years, and thus, it will be the "base case". The other analysis will simulate the base case but with estimated DG penetration over the planning horizon. This case will be the "new case".

By using the results from the two cases (mainly looking at the difference between two cases) the following quantities will be obtained to estimate the impact of DG on the feeder:

a. Determine how much of system upgrades can be avoided/deferred due to new DG growth. This will help us to identify and quantify the avoided/deferred capacity on the feeder.
b. Voltage profiles on the feeder under different operating conditions over the simulation period. These profiles will enable us to assess the voltage quality issues, such as high and low voltage conditions, and excessive voltage variations that may cause device misoperation, such as CAP switching.
c. Identify the system components (overhead and underground lines, protective and switching devices and voltage regulation and control equipment) that may be overloaded, and quantify the severity of the overload.
d. Determine the increase in operation of LTCs and voltage regulators (tap changes) due to DG connection, and identify which one of these devices experience excessive operation due to DG penetration.
e. Determine the increase in switched capacitor banks operations due to DG connection.
f. Determine the change in annual energy losses due to DG connection.
g. Determine the impact of DG on Volt-Var control (DSDR).
h. Identify mitigation measures and system upgrades that are needed in order to accommodate the DGs while maintaining the quality of service.

The results obtained from these steps will help us to quantify the main cost-benefit components considered:

- Capacity deferral from step *a*,

- System loss reduction from step *f*,
- Impact on substation equipment from steps c and d,
- Impact on feeder equipment from steps *c, d*, and *g*,
- Impact on system operation (mainly on Volt-Var control) from step *g*.

2. System Protection

This activity will involve conducting a set of protection system assessment studies on a set of selected feeder in or der to quantify the protection related issues identified in *Step I*, mainly focusing on the main issue identified – the extra stress on substation equipment as a result of slower fault clearing due to DG. The case study to be conducted for this purpose will involve the following steps:

i. A set of selected feeders from Duke Energy will be used. Duke energy will provide the protection devices used on these feeders and the data related to these devices, such as protection settings of the feeder protective devices (relays, reclosers, and fuses).

ii. The software CYME will be used (it is the same software Duke Energy uses) to do system protection assessment on the selected feeders under two conditions: first the base case (no DG) and the new case (with DG). Proper models for the PV systems will be adopted to reflect the limited fault current contribution from PV systems.

iii. The results from these simulations will then be used to assess the impact of DG on the protection system on the distribution system simulated. This will involve the following steps:
   - Increase in the tripping time of the relays due to DG,
   - Additional fault Energy absorbed by substation equipment (Transformers etc.) due to increased tripping time. The additional fault energy will be used to estimate the life time degradation of substation equipment due to slower clearing of faults on a distribution system.

II.3.2 Estimating Components based on Historical Data

There are some component that will not be easy to quantify through simulations, mainly

- System Operation (C.4): The improvements needed in the DMS system to better monitor the system, and the extra efforts involved in outage management on feeders with high DG penetration.

- Operation planning (C.5): Extra effort involved in identifying the native load on a distribution feeder.

To quantify these components, the team will work with engineers from Duke Energy who are familiar with these issues. Historical cases and related data will be used to get an estimate on these components.

APPENDIX

Exhibit I: First DG Cost of Service Meeting

Date: January 27, 2020 | 9 a.m. to 12 noon

Agenda –

Duke Energy arranged interview sessions with experienced staff that could share their field experiences with the NC State study team. The meeting sessions were divided into two parts, the first session relating to field experiences with DG impact on the distribution system Operation and Management (O&M) and the latter session on DG impact on substation O&M.

Attendees -

Duke Energy: Nate Finucane, Clifton Cates[1], Juhua Liu[1], Jim Umbdenstock[1], Waheed Oyekanmi[1], Mike Grant[1], Joseph Grappe[1], Andrew Parkes, Maura Farver, and Stephen Shuford[2]

NC State University: Mesut Baran, Wenyuan Tang, Keith D'Souza, and Rishabh Gupta

Advanced Energy: Tommy Cleavland[2]

([1] – Session # attended by the participants. Others attended both the sessions.)

Session 01 - Field Experiences with DG impact on Distribution O&M

Meeting Focus: Identify impacts due to ongoing Operations and Maintenance (O&M) costs and unidentified system costs not captured in the interconnection studies, mainly considering the impacts on:

- Capacity Planning
- Operation
- System Maintenance

Distribution Capacity Planning

- **Feeder Capacity**: Feeder capacity/loading is assessed by considering only the native load. The DGs are backed out at the peak time and then the capacity requirement/ reserves are calculated. Hence DG impact is mainly increased engineering effort to extract out the DG to determine the native load.

- **Load Masking:** This issue complicates planning due to non-visibility of native load.
    - At DEP, large PV farms are metered, and this data is synced with the load profile to unmask the native load. Small scale PV installations are not metered, and thus load unmasking is more challenging on feeders with this type of PV systems.

- This task is done on a feeder basis. Hence, when there are DG generation, then the planners have to spend more time to unmask the load.
- In DEC, the majority of its territory is rural and no advanced metering tools have been deployed (PV size unknown, GIS unreliable). Hence, the native load estimation is done manually and thus it is more time consuming for feeders with PV installations.

- **Reverse Power Flow:** In DEC, some substations experienced the problem of reverse power flow. Some equipment may be affected by the reverse power flow. Equipment failures at the substation took place; however, the equipment was old, hence it was difficult to attribute the failure to DG. There is a system in place to do more frequent inspection of LTC and voltage regulators (VR) to assess accelerated aging at substations with large PV farms.

- **Voltage regulator (VR) operation:** Recently, both DEC and DEP has started connecting utility scale PV before the first line VR in order to reduce impact on voltage regulators. However, substation VR needs to manage power flow and voltage variations, and this may affect its wear-and-tear.

System Maintenance:

- **Circuit Re-configuration:**
  Feeder reconfiguration is performed to alleviate loading concerns on a feeder. Planners review feeders with PV to confirm if the reconfiguration with PV is feasible. If the reconfiguration is not feasible, then some mitigation measures are needed and may include asking PV farm to curtail its output.

- **System Upgrades for mitigating DER impacts:**
  As a pilot project, a new fast acting Var compensator, D-VAR, was used on a circuit with high PV penetration to mitigate harmonics and voltage issues, and they helped reduce the regulator operations. Duke Energy may expand adopting these devices on feeders with high PV penetration and this sometimes may need to be done after the PV farm(s) are connected.

- **Power Quality:**
  - After the DG interconnection, the voltage/power quality issues sometimes appear/surface. Typically, the issues were raised by DG customers. These issues are investigated and mitigation measures are taken by the PQ team.
  - DEP has experienced the power quality problems when there is a large PV farm on a feeder. Some of the issues experienced include:

- Capacitor Bank Cycling**:** On a feeder with large PV farm, when the PV output changes suddenly and considerably (due to cloud cover etc.), capacitor banks may switch in and out. This results in increased operation of Capacitor banks.
- Load Rejection: Solar inverter may shut down as capacitor banks come online due to temporary over-voltages, and this can result in load rejection.
- Transformer Inrush – During transformer energization at a large PV farm, the large in-rush causes voltage sag on the feeder and this causes other equipment on the feeder (DVAR, controls etc.) to miss-operate. It is difficult to estimate this issue during interconnection study, and therefore when it is experienced after installation, extra mitigation measures are needed.
- Temporary Overvoltage: When PV is disconnected by the Recloser (RC) to disconnect the PV farm, over-voltage on inverter can reach up to 2p.u., leading to lightning arrestors being fired and other equipment failure. Duke has meters and CTs on the solar side of the recloser which also can get damaged.
- High Frequency Harmonics**:** PV inverters are solid-state devices and can generate high harmonic currents, up to 49th harmonic. These high harmonic currents flow through the system unimpeded. The impact of these harmonics are observed in California and include interference with cellular phones and resonant issues on the system (similar to RFI).

System Operation

DEP employs a DMS system for online monitoring and management of its distribution system. Duke Energy has also adopted the self-optimizing grid (SOG). Both of these systems may need upgrades to handle operation of feeders with high PV penetration. One of the functions impacted by large PV farms is the FLISR. Implementation of FLISR requires closer operator supervision and coordination with field crew to operate switches and recloses when DER is in the system.

Session 02 - DG impact on substation

- **Substation Voltage Regulators:**
  - DG caused a steep increase in operations of VRs due to ramping and intermittency.
  - Duke Energy started using new Arcless/vacuum regulators and they have much higher operation limits. During past few years, some of the old regulators have failed.
  - Higher VR operation made it necessary to increase the maintenance frequency of VRs. Now, dissolved gas analysis done every six months. Earlier, maintenance used to be performed every 2 years.
  - At DEP, VR settings has been made tighter for DSDR. This increased the VR operation.

- **Fault indicators/ detectors**: batteries for these sensors need some current on the line to charge. With DG, they need to use their batteries more often. Hence, batteries need to be inspected and replaced more frequently.

- **Protection Co-ordination**: As more DGs are added, the response of protection relays becomes slower in clearing faults. There is a concern this will affect equipment lifetime due to the slower fault clearing times. This is deemed to be low impact.
- **Transformer Connection**: Step up transformers used at PV farms for interconnection are connected in Delta at PV side. One of the issues with this connection is that, during a fault close to such a transformer, line voltages can reach to 2 p.u. on un-faulted phases. This may result in arrestor firing and/or insulation failure which may in turn convert a temporary fault to a permanent one.

- **DG service period:** If the DG provider leaves the project after 15-20 years, the utility still benefits from the upgraded infrastructure built for the DG.

Exhibit II: Second DG Cost of Service Meeting

Date: March 02, 2020 | 9:30 a.m. to 11 a.m.

Attendees -

Duke Energy: Nate Finucane, William Armstrong, Amanda Longman, and Andrew Bilitski

NC State University: Mesut Baran, Wenyuan Tang, Keith D'Souza, and Rishabh K. Gupta

- **DSDR (Distribution System Demand Response):**
  - DEP currently uses DSDR to reduce demand. It provides average 3.6% voltage reduction.
  - DEC is planning a volt-var optimization program similar to DSDR which aims to reduce energy, DEP uses DSDR to reduce peak demand, but is also planning a new volt-var optimization program which will aim to reduce energy.
  - It is difficult to optimize DSDR when there is a variable source of energy such as a PV farm on a distribution system.

- **VR operation:**
  - Increase in VR operation: PV variability causes VRs to operate more frequently. On cloudy days LVRs are rapidly subjected to forward and backward regulating modes. New requirement on connecting large PV farms upstream within the substation VR zone helped minimize PV impact on LVR operation, but substation voltage regulators are still impacted. Also, several grandfathered PV installations may exist downstream from LVRs.
  - The control mode for LVRs may need to be improved: Control mode sometimes need to be changed manually between Cogen and Bidirectional Mode after a feeder reconfiguration. Duke Energy is in the process of upgrading these control so that they can change the mode automatically.
  - Software upgrade to handle VR control modes: DMS Software needs to be upgraded to take into account the proper mode of operation of the VRs, also DMS needs additional real time data to monitor and verify their control mode.
  - New VRs can tolerate much higher operation. However, their cost is substantially higher.

- **Feeder Reconfiguration:** During periods of light loading (spring, fall), feeders are reconfigured to transfer loads. Presence of DERs complicates this exercise due to potential for reverse power flow under high DG output; DERs might need to be taken offline if necessary. For some challenging cases, DER impact group performs studies to determine the proper reconfiguration option.
- **Power Quality:** Impact of varying voltage on industrial load can be high. A case study is conducted by EPRI at an industrial facility by Campbell Soup.

- **DVAR:** DVARs are currently operated independently from the DMS system. When DSDR is activated, new voltage targets must be manually sent to the DVAR as DVARs are not modeled into our Distribution Management System (DMS) yet. Currently only 2 feeders have DVAR.

- **System Protection**
    - There has been no issue related to PV farm not tripping after a fault. Usually, recloser opens as soon as it measures voltage on Duke Energy's end.
    - Most of equipment on distribution system is immune to over-voltage issues caused by DERs inverters (for example, BIL of reclosers is 100kV).

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DG Cost of Service: Sample Case Studies

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Preface

This is the second report of a study conducted by a research team at NC State university which aims at development of a methodology for assessing the cost of service components associated with Distributed Generation (DG) connected to a utility distribution system. The study was undertaken as part of the NC PUC commission order issued on June 14, 2019 which asked for a testimony characterizing the benefits that distributed generators are receiving from the Utility's Systems, estimating their share of the related costs, and providing options for fully recovering those costs from distributed generators. The first part of the report focused on development of the methodology and was submitted to Duke Energy with the title "Framework for Estimating DG Cost of Service", on 12^{th} Oct 2020.

1 Introduction

This report summarizes the results of a case study conducted to demonstrate the proposed cost of service methodology for Distributed Generation (DG) using various feeder configurations.

The cost of service components proposed in the methodology are as follows:

1. Substation Capacity Deferral
2. System Loss Reduction
3. Substation Equipment Service Life
   (a) TR (Transformer) or OLTC (On Load Tap Changer)
4. Feeder Equipment Service Life
   (a) Voltage regulators (LVR) and switched capacitors (CAP Banks)
5. Distribution System Loss Reduction
6. Feeder Upgrades
   (a) Equipment replacement due to voltage violations and thermal violations
7. Distribution System Operation and Maintenance: Protection, Monitoring, and Control.

The last component is not included in this case study, as it relates to actual system operation related activities.

1.1 Assessment Methodology

To estimate the cost-of-service components considered, the following methodology is adopted to quantify them:

1. Consider a planning horizon over 10 years
2. For each year of the planning horizon simulate feeder operation for two cases:
   - Base: No DG (only load growth)
   - New PV: Feeder with estimated PV (mainly solar farm) penetration up to year 5, no PV growth thereafter.
3. Capture the key performance metrics in the simulation:
   - Number of operation of devices OLTC, LVR, and CAP Banks (switched)
   - Equipment overload: duration, extent of overload
   - Voltage Violations: extent of violation
   - Reverse Power flow: extent of reverse power flow, along with peak demand at substation (kW and kVA)
   - System losses: cumulative (kWh)
4. Estimate the cost of each service component using the performance metrics obtained in step 3.

2 Case Study

The proposed methodology has been used to estimate the cost of service components on four different distribution systems. Table below gives the main statistics about these systems. As the table shows, the first system represents a simple distribution system with only one feeder - 123 node sample feeder. The other three systems represents more common distribution system with varying number of feeders supplied from a substation. System 2 and 3 both have multiple feeders, one of which is large (EPRI J1 feeder) and others are smaller feeders. The fourth case is based on an actual distribution system from the local utility with three large distribution feeders. Case studies on these four diverse systems provide a basis for establishing any trend and commonalities, as well as highlight any differences in results between them.

In the following subsections, the individual feeders are introduced first, and then two different load growth scenarios considered for each case is outlined. These two load growth scenarios reflect the two likely scenarios the local utility considers in their planning studies. Finally, the PV growth for each case is given in section 2.2. These growth scenarios reflect the typical high PV penetration the local utility has seen in recent years. Note also that in cases 2-4, one of of the feeders does not have PV growth (which is indicated in table 1), and these cases are considered in order to ascertain if feeders without PV can experience negative impacts due to being part of a distribution system with PV.

Table 1: Distribution Systems

	Case 1	Case 2	Case 3	Case 4
Feeder Configuration	IEEE 123 Node	EPRI J1 + IEEE 123 Node – No PV + IEEE 123 Node – PV	EPRI J1 + IEEE 123 Node – No PV + IEEE 123 Node – PV1 + IEEE 123 Node – PV2	B01 + B02 + B03
Circuit Voltage	12.47kV	12.47kV	12.47kV	22.86kV
Transformer Rating	15MVA	25MVA	30MVA	25MVA
Peak Demand	10MVA	20.3MVA	29.5MVA	19.5MVA
OLTC	1	1	1	1
LVRs	6	8 + 6 + 6	8 + 6 + 6 + 6	0 + 8 + 6
CAP Banks	1	5 + 1 + 1	5 + 1 + 1 + 1	2 + 4 +4
Total Capacitance	50kVAR	4 MVAR	4.05 MVAR	9.6 MVAR

2.1 Test Feeders

To further illustrate the systems considered in the four cases, the basic information about the feeders on these system are given below:

1. IEEE 123 Node Feeder (in case 1 & 2):

   Figure below shows the one-line diagram of this feeder. The figure shows also the simulated PV growth on it. As indicated in the figure, all utility scale PV farms (large yellow spheres) are placed in the first voltage regulation zone, i.e., upstream of the first LVR on the main feeder. This PV growth emulates the practice adopted by the local utility. The locations were varied between cases to observe the variations between the cases. Also, all PV systems are assumed to operate at unity power factor (which is a common practice) and do not possess any advanced inverter control mechanisms such as Volt/VAR or Volt/Watt control.

   Figure Key:
   Blue cube: substation
   Magenta Tetrahedron: LTC/LVR
   Black Tetrahedron: transformer
   Green Cylinder: capacitor
   Red cube: load

Yellow sphere (large): Utility scale PV
Yellow sphere (small): Rooftop PV

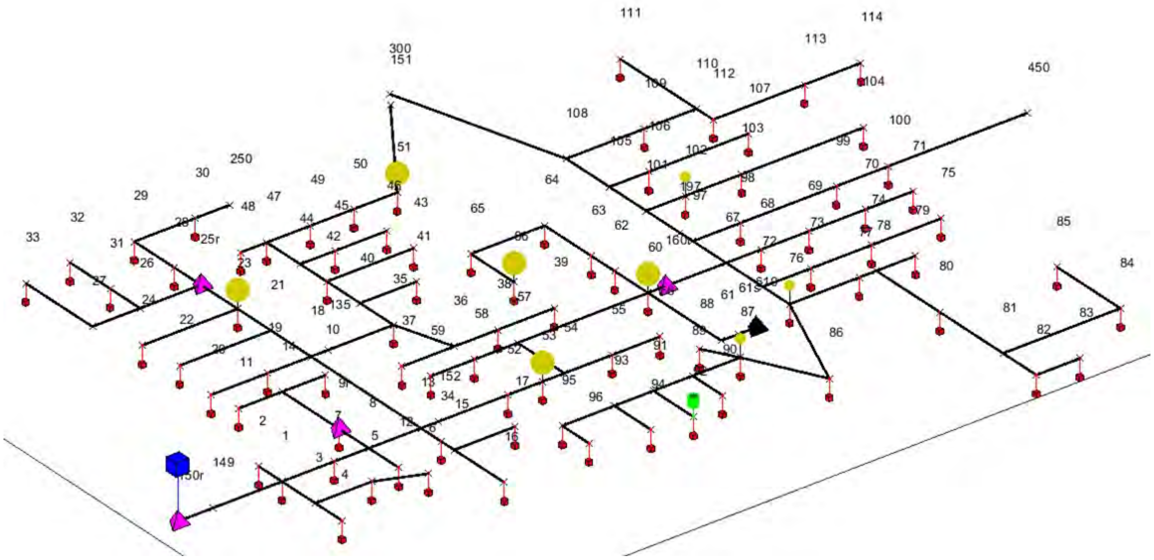

Figure 1: IEEE 123 Node Feeder

2. IEEE 123 Node Feeder (in Case III):
   The IEEE 123 node feeder used in Case III is the same as that used in Case I and II apart form the location of the utility scale PV farms. The locations of all PV farms are shown in Fig. 2 and 3.

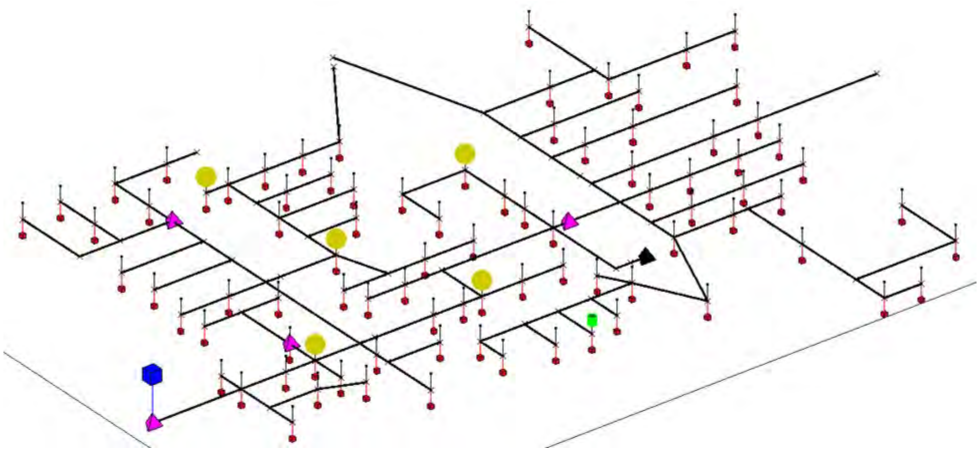

Figure 2: IEEE 123 Feeder - PV1

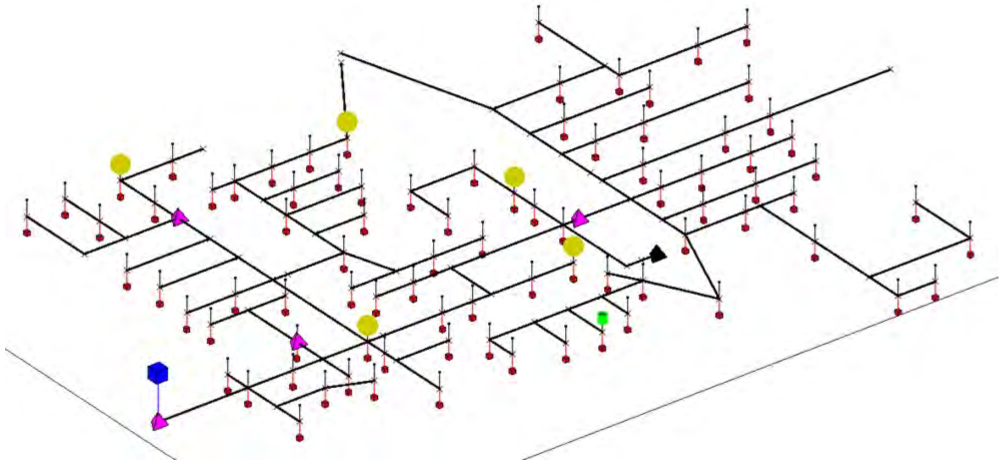

Figure 3: IEEE 123 Feeder - PV2

3. EPRI J1 Feeder:

   The EPRI J1 feeder (shown below) is an actual utility feeder that is used by EPRI to test the impacts of high penetration PV deployment. Modifications were made to this feeder's substation transformer (changed to 25MVA from 15MVA) in order to accommodate additional feeders considered in Cases II and III.

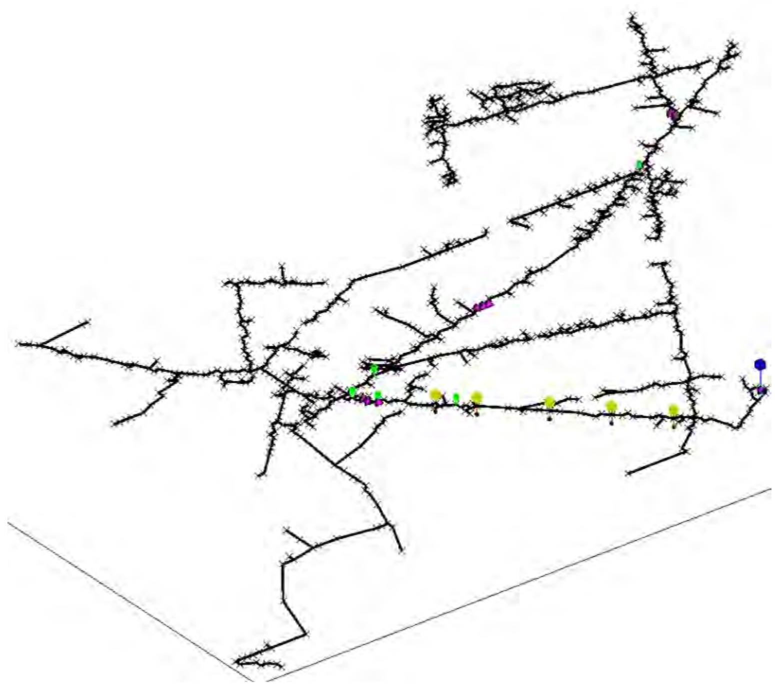

Figure 4: EPRI J1 Feeder

4. Large Three-Feeder Distribution System:
   This is an actual system provided by the local utility and it consists of the three feeders referred to as B01, B02, and B03. Figure below shows the system.

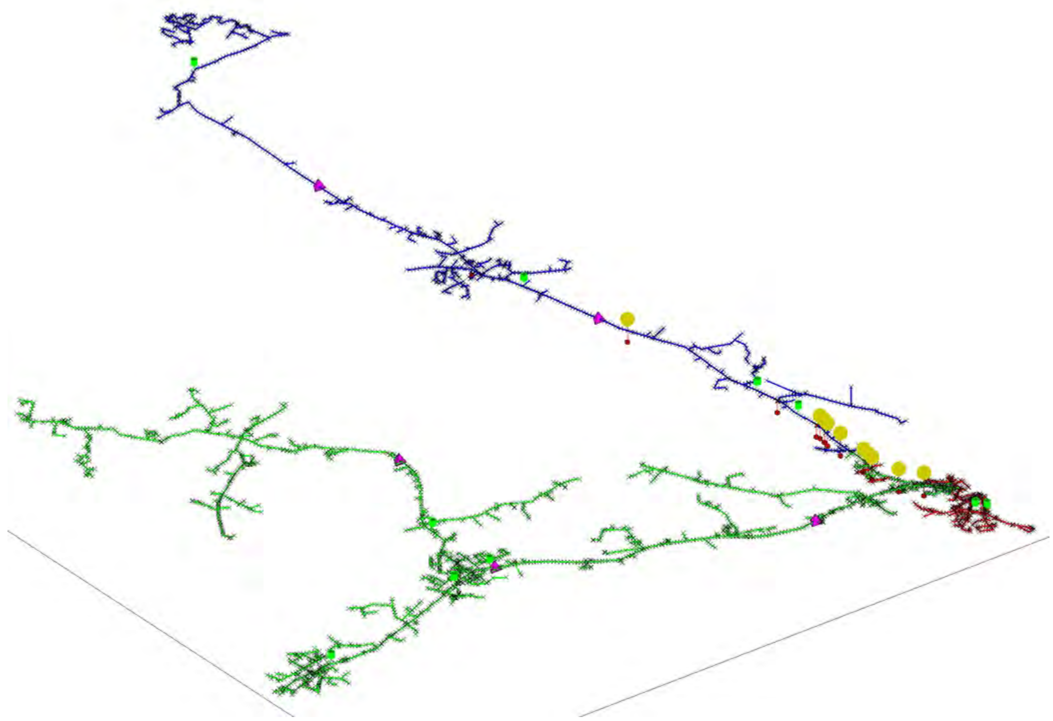

Figure 5: Case 4: large scale distribution system

2.2 PV growth

The amount of utility scale and rooftop PV connected in the system for each year of the time horizon for each configuration is shown in table 2, 3, 4, and 5.
As mentioned in the methodology, the PV penetration is held constant from year 5. Based on the guidance received form local utility, the maximum PV penetration was dictated by the substation transformer rating, i.e. the maximum permissible total installed PV capacity (MW) was equal to the substation transformer rating (MVA).

Table 2: Config .I - PV Penetration

Year	**PV Utility Scale (MW)**	**PV distributed (kW)**	**% PV**
0	0	0	0%
1	3	200	32%
2	6	218	62%
3	9	237.62	92%
4	12	259.01	123%
5	15	282.32	153%
6	15	282.32	153%
7	15	282.32	153%
8	15	282.32	153%
9	15	282.32	153%
10	15	282.32	153%

Since distributed/rooftop PV installation were significantly smaller in size compared to utility scale PV farms, and did not tangibly affect the cost of service, they were not included in case 2, 3, or 4.

Table 3: Case 2 - PV Penetration

Year	EPRI J1		IEEE 123 Node	
	PV Ut Sc (MW)	**% PV**	**PV Ut Sc (MW)**	**% PV**
0	0	0	0	0%
1	2	40%	3	40%
2	4	80%	6	79%
3	6	120%	9	119%
4	8	160%	12	158%
5	10	200%	15	198%
6	10	200%	15	198%
7	10	200%	15	198%
8	10	200%	15	198%
9	10	200%	15	198%
10	10	200%	15	198%

Table 4: Case 3 - PV Penetration

Year	EPRI J1		IEEE 123 Node – PV1		IEEE 123 Node – PV2	
	PV Ut Sc (MW)	**% PV**	**PV Ut Sc (MW)**	**% PV**	**PV Ut Sc (MW)**	**% PV**
0	0	0	0	0%	0	0%
1	1.5	30%	2	26.3%	2.5	32.89%
2	3.0	60%	4	52.6%	5.0	65.79%
3	4.5	90%	6	78.95%	7.5	98.68%
4	6.0	120%	8	105.26%	10.0	131.58%
5	7.5	150%	10	131.58%	12.5	164.47%
6	7.5	150%	10	131.58%	12.5	164.47%
7	7.5	150%	10	131.58%	12.5	164.47%
8	7.5	150%	10	131.58%	12.5	164.47%
9	7.5	150%	10	131.58%	12.5	164.47%
10	7.5	150%	10	131.58%	12.5	164.47%

Table 5: Case 4 - PV Penetration

Year	B01		B03	
	PV Ut Sc (MW)	**% PV**	**PV Ut Sc (MW)**	**% PV**
0	0	0	0	0%
1	2.5	35.71%	2.5	32.59%
2	5	71.43%	5	65.19%
3	7.5	107.14%	7.5	97.78%
4	10	142.86%	10	130.38%
5	12.5	178.57%	12.5	162.97%
6	12.5	178.57%	12.5	162.97%
7	12.5	178.57%	12.5	162.97%
8	12.5	178.57%	12.5	162.97%
9	12.5	178.57%	12.5	162.97%
10	12.5	178.57%	12.5	162.97%

In each configuration, Feeders not mentioned in the above tables have no installed PV on them.

2.3 Load growth

- Scenario I: Peak Load Growth rate 0.21%, Energy Growth -1.02%
- Scenario II: Peak Load Growth rate 1%, Energy Growth 0.6%

The base year load and PV profile were provided by Duke Energy. Figure 6 shows the load growth profile. Quantities X and Y indicated in the figure are used to adjust the growth rate for each year (i).

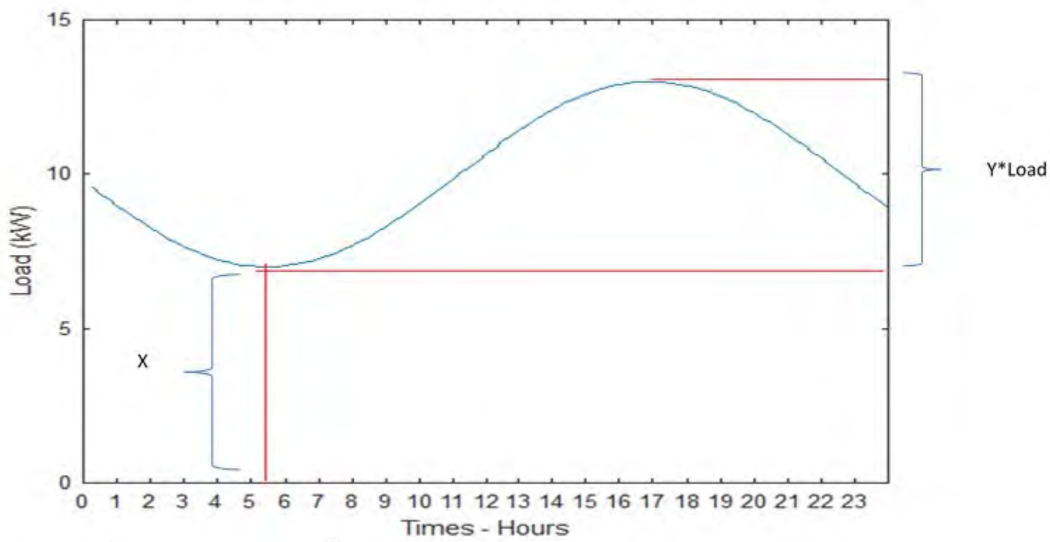

Figure 6: Load Scaling Example

Scaled load profiles along with time synchronized PV profiles provided by local utility are used to simulate the system operation for each year. Data resolution for the load and PV is one minute (8760x60 minutes(samples) per year) for case 1 and 10 minutes (8760x6 samples per year) for case 2, 3, and 4. OpenDSS was used to perform the time-series analysis. PV contribution is represented as negative demand.

The results for each feeder configuration are presented in the subsequent section for each load growth scenario.

3 Simulation Results - Case I

Simulations have been performed under the two different load growth scenarios.

3.1 Load growth scenario I

Peak Load Growth rate 0.21%, Energy Growth -1.02%

The results obtained from simulations are summarized below. The summary compares the change in each metric considered as PV penetration increases over the planning period.

3.1.1 Substation Capacity Deferral

To see how much capacity upgrade can be deferred at the substation as PV penetration increases, we monitored the peak demand at the substation (in kVA and kW) and the results are shown in the figure below. Comparing kVA in the PV case to the base case, we see a decrease in the peak demand as PV penetration increases up to year 3, after which we see a reversal in trend. The potential for capacity deferral depends on the capacity of the substation equipment. In this case we assumed that substation transformer is rated 15 MVA and therefore it has enough capacity to accommodate even the increase peak demand at very high PV penetration level reached in year 5. Since, in this case transformer has enough capacity for the native load, it is deemed that PV does not defer any capacity upgrade.

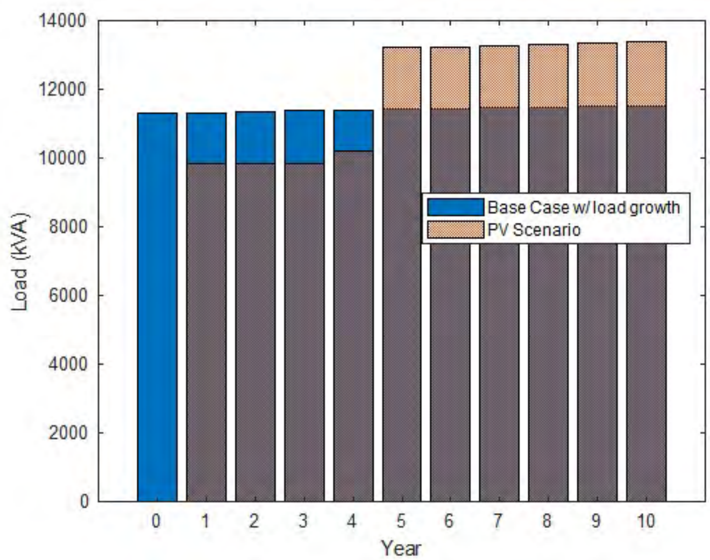

Figure 7: Yearly peak demand at the substation - with and without PV

To further explain the results, Figures 8 and 9 compares the real power demand (kW) at the substation in year 10 (only for phase A) which has the highest load and PV. We see that there is significant reverse power flow in all seasons, especially spring and fall. The magnitude of reverse power flow is close to that of the native load and its total duration is also considerable - amounting to 33.96% or 124 days a year in year 10. Note also that there are periods in base case where demand becomes really small due to the declining energy growth profile assumed in this study, and that is the main reason for having the kVA flow (in the PV case) at the substation higher than that of the base case.

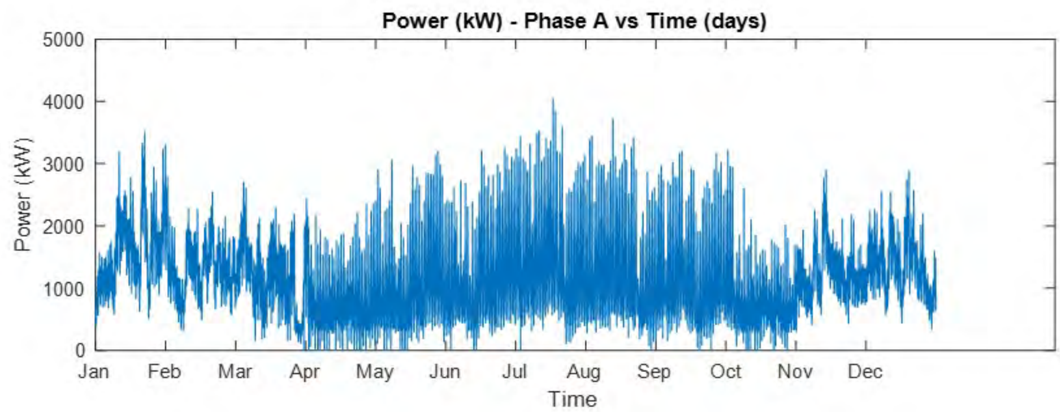

Figure 8: Net load at substation during year 10 - No PV

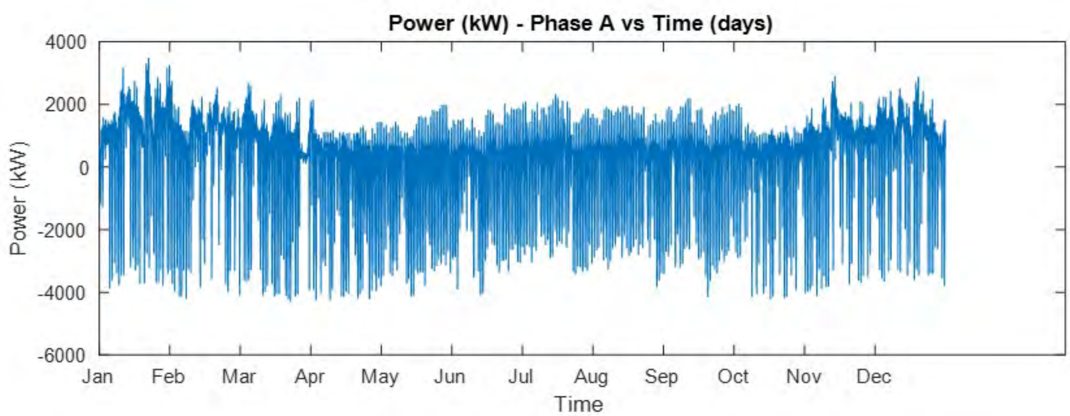

Figure 9: Net load at substation during year 10 - with PV

Figures 10 and 11 show the kVA demand profiles during year 10. When we compare the yearly demand between the two cases, we see that PV causes the feeder peak demand to shift from summer (13.4 MVA) to winter (11.5 MVA). It must be noted that kVA is an unsigned quantity i.e. it represents only the magnitude of power flow and not the direction.

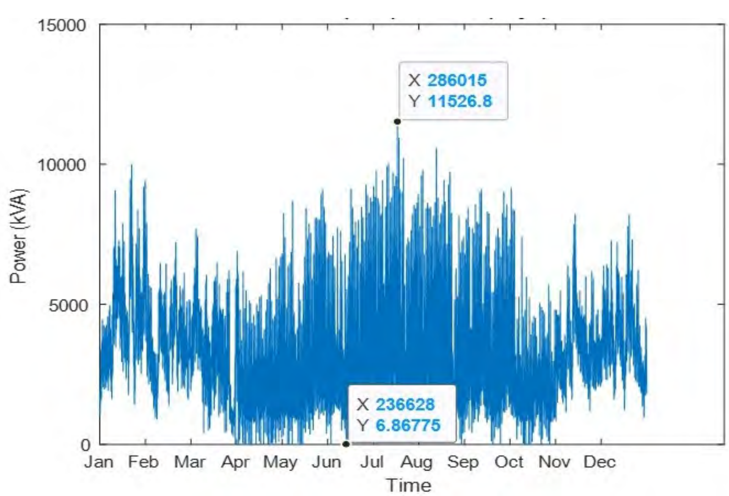

Figure 10: Net load profile during year 10 - base case (No PV)

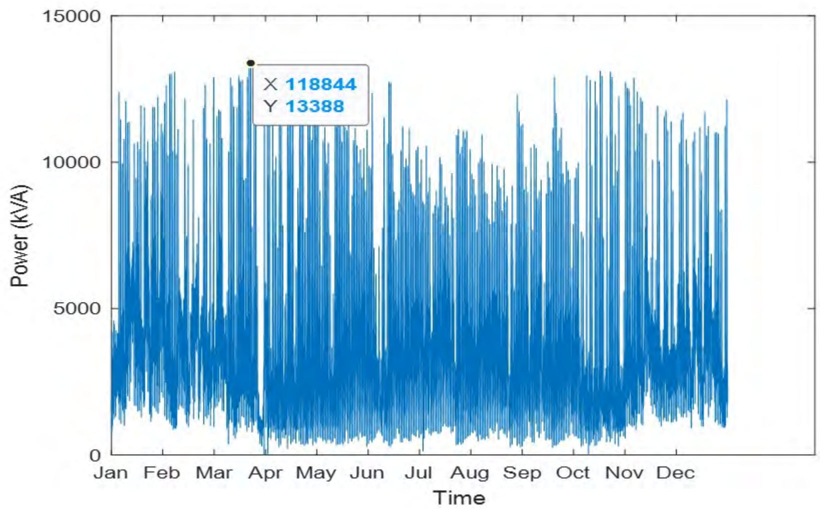

Figure 11: Net load profile during year 10 - with PV

3.1.2 Substation Equipment Service life

OLTC Operation: In this system, the transformer at the substations is of type OLTC (On Load Tap Changer). We monitored the operation of OLTC, and the figure below shows the results. As figure 12 illustrates, the number of operations (each tap movement is considered an operation) are marginally reduced at low PV levels in year 1–2 (50% PV), and the operations quickly rise as more PV is added (up to year 5 after which no additional PV is added).

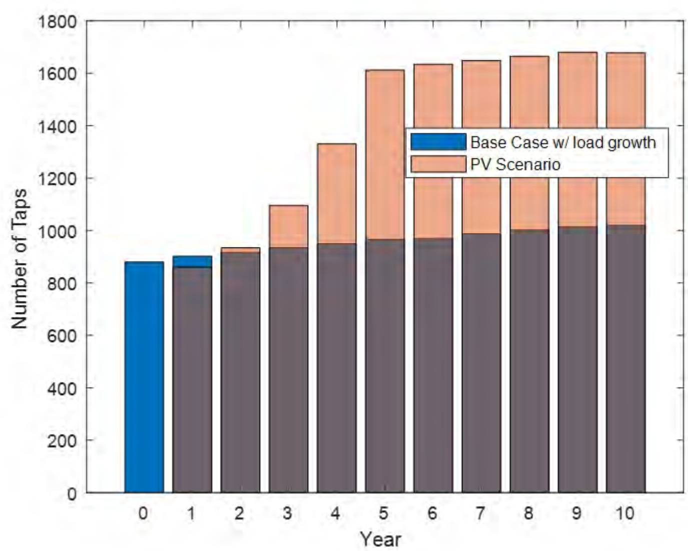

Figure 12: OLTC operations per year with and without PV

Transformer Loading: The simulations indicated that at moderate levels of PV penetration, the loading on the substation transformer decreases, therefore this will help prolong the lifetime of the transformer. To estimate this expected benefit, a thermal model for the transformer is adopted and used to estimate its hot spot temperature as this temperature is the main factor affecting the degradation of the transformer lifetime under normal loading conditions. Details of the model developed for this purpose is given in the Appendix I. For this case it is assumed that the transformer rating is 15 MVA, which reflects a moderately loaded case, as the maximum native load is 11.3 MVA. The transformer loss of life with and without PV penetration is shown in Figure 13 on a yearly basis. This figure shows that PV reduces the loss of life. As the figure shows, the loss of life starts decreasing as PV penetration increases from year 1 to year 3, and then increasing as the PV penetration approaches high levels in years 4 and 5. From year 5 to year 10, the loss of life almost remains the same since the PV penetration saturates at 153% since year 5. The loss of life reduction is less than an hour per year, under all scenarios. These results indicate that transformer loss of life reduction due to PV will not be significant under typical loading conditions

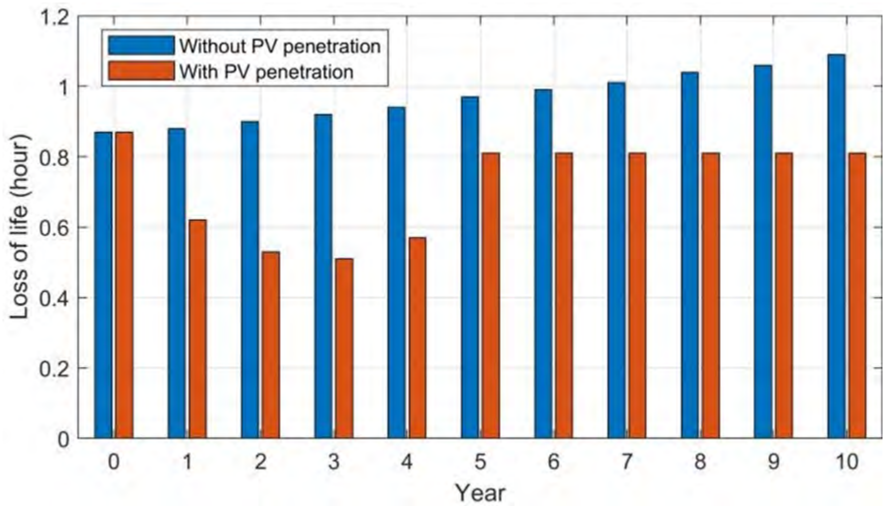

Figure 13: Comparison of transformer loss of life, with and without PV

3.1.3 Feeder Equipment Service Life

To assess the impact of PV on feeder equipment, we monitored the operation of LVRs, and CAP Banks. Figure 14 shows the operation of 3 LVRs on the feeder. These results indicate that PV impact on LVRs is similar to that of OLTC: PV reduces LVR operation marginally up to moderate level of penetration during the first 2-3 years (60-80% penetration) and then there is considerable increase in operation at higher levels (120-150% penetration). Results also show that that proximity of LVR with to PV makes a marginal difference in the operation.

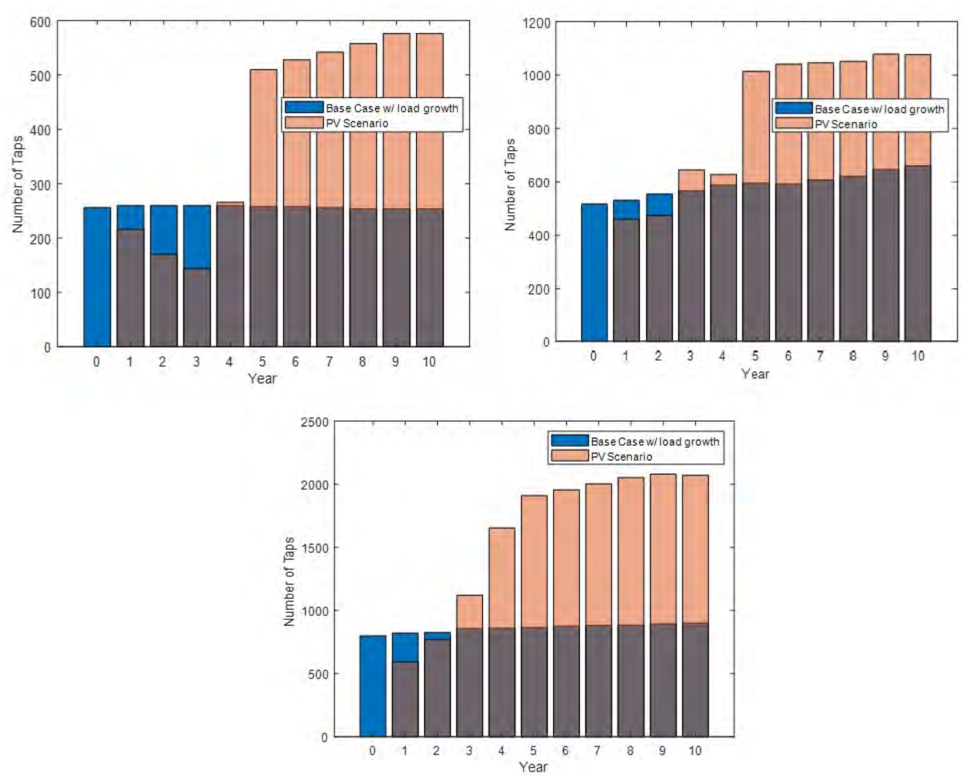

Figure 14: LVR operations per year with and without PV, Top Left: LVR 1, Top Right: LVR 2, Bottom : LVR 3

Figure 15 shows the change in CAP Bank switching as PV penetration increases on the feeder. The results illustrate that PV reduces the CAP operation marginally at low penetration levels and increases CAP operation at high PV levels in year 4 and beyond.

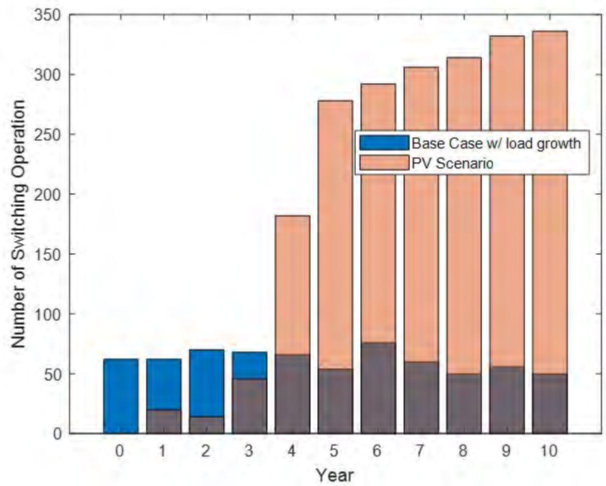

Figure 15: Capacitor switching per year - with and without PV

3.1.4 Distribution System Power loss

Real power loss on the feeder is monitored during the simulations to get an estimate of how much PV penetration reduces the power loss on this feeder. Figure 16 shows the simulation results. We see an initial reduction in power loss at lower penetration (60-90%) in years 1-3 and then power loss raises sharply as PV penetration gets higher in years 4 and 5. For reference, the loss in the base case for year 0 is 99 MWh and year 10 is 86 MWh. While the losses in year 10 with PV amounts to 139 MWh i.e. 61% increase in losses.

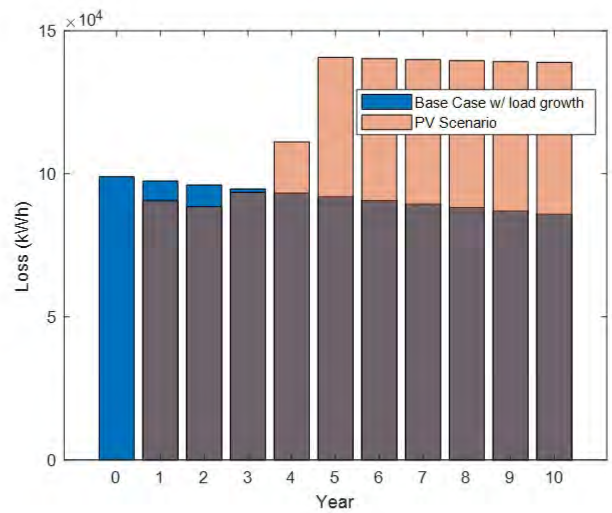

Figure 16: Total system losses per year - with and without PV

3.1.5 Feeder Upgrades

Line Section and Equipment Overloading: In this system, some of the line sections get overloaded as PV penetration gets high. The algorithm used to identify overloads is given in the Appendix II. Table 6 shows the line section overloads over the study period due to PV integration. It must be noted that there were no overloads in the base case. Figure 17 shows the lines overloaded. Note that these are mainly the line sections on the backbone that experience overloads due to the large amount of reverse power flowing back to the substation. These overloaded line sections need to be upgraded, and in this study, it is assumed that the upgrading will be done as PV farms being integrated and the associated cost will be recovered through the PV interconnection service.

Table 6: Thermal overloading on line sections with PV

With PV						
Initial Overloading				**Final Overloading**		
Year	**Equipment**	**% Max Loading**	**Duration (hours)**	**Year**	**% Max Loading**	**Duration (hours)**
5	'l115'	102.59	18.5	10	104.61	23.45
5	'l3'	103.20	21.3	10	105.16	26.56
5	'l7'	103.27	21.75	10	105.23	26.96
5	'l10'	103.74	24.1	10	105.65	29.85
5	'l52'	93.60	1.1	10	95.32	2.31
5	'l116'	93.38	0.87	10	95.11	2.05

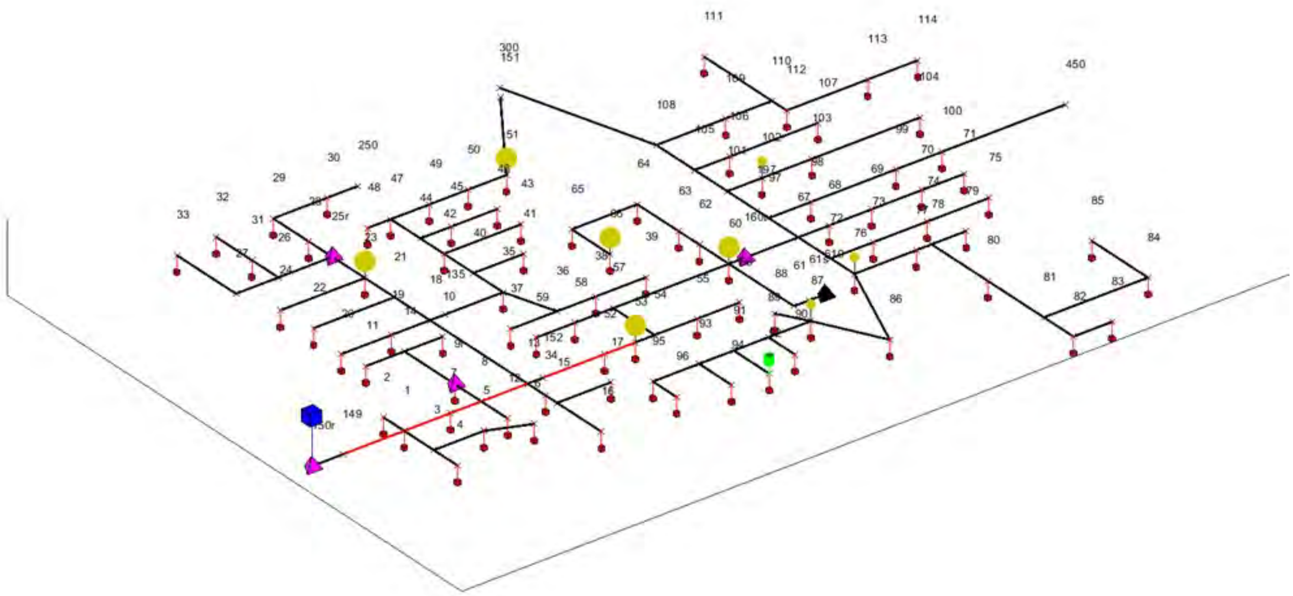

Figure 17: Equipment & line overloads in year 5 with PV

Voltage Violations: It is assumed that when the feeder starts experiencing voltage violations, some upgrades are needed to mitigate these violations. Figures 18 and 19 show the variation in maximum and minimum circuit voltage for both the base case and with PV. When we compare the maximum circuit voltage, with and without PV, we see no perceptible difference in the maximum voltage variation at lower penetrations. However, at higher penetrations, it seems that the maximum circuit voltage has dropped a bit.

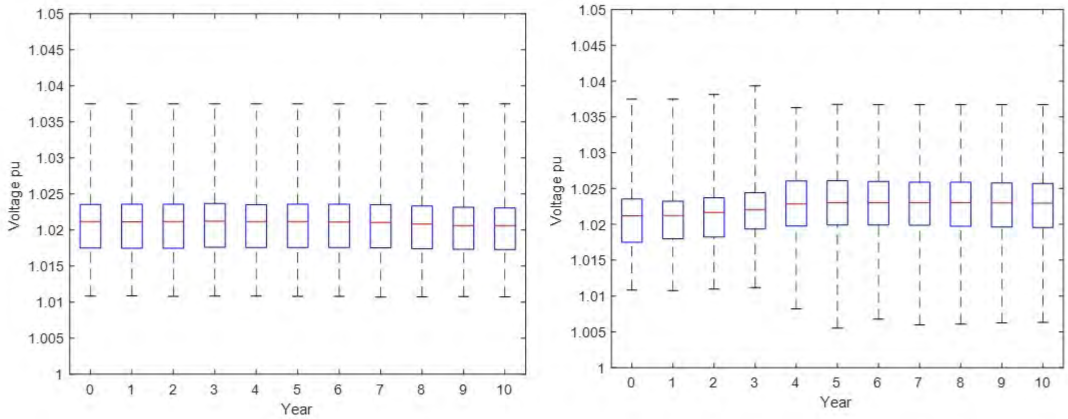

Figure 18: Maximum circuit voltage for each year of the planning period, Left: No PV, Right: with PV

The figure below shows low voltage statistics on the feeder for both the base case and case with PV. The results indicate that the minimum circuit voltage tends to reduce, approaching the minimum voltage limit.

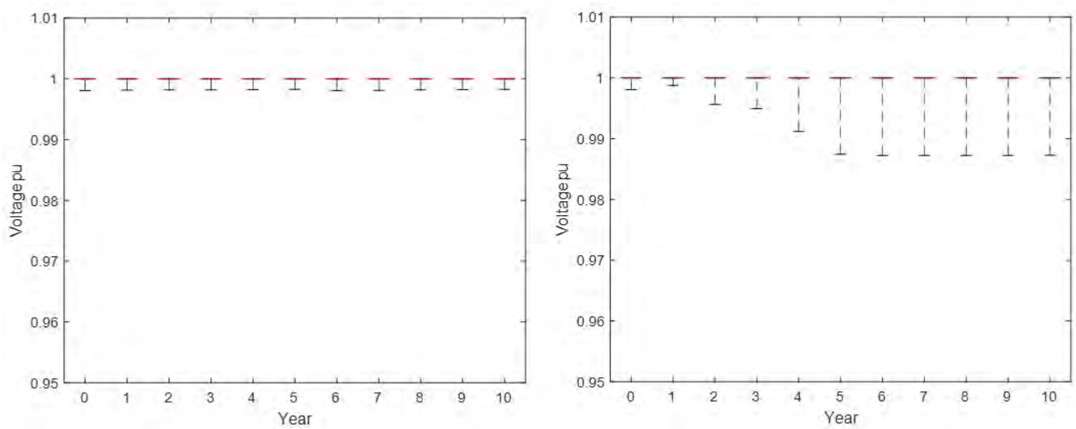

Figure 19: Minimum circuit voltage for each year of the planning period, Left: No PV, Right: with PV

Note that no voltage violations are observed under both the base case and with PV, and hence, it is deemed that no feeder upgrades are needed for this purpose.

3.2 Cost Estimate for Service Components

3.2.1 Substation Capacity Deferral

Simulations indicate that PV relieves some capacity up to moderate levels of penetration for the given load and PV profiles. From figure 7, using year 3 results, the capacity relief is (kVAbase – KvaPV)/(PVcapacity) = (11.5-9.7)/9 = 13%. However, when PV penetration reaches above 150% in year 5, kVA demand goes higher than that of the base case, which therefore indicate the need to upgrade the capacity at the substation. Since in this case this cost associated with this upgrade will be allocated directly to the PV owner, this component is not included as part of the cost of service component.

3.2.2 Substation Equipment Service Life

Simulations indicated that PV affects the tap operation of both the LTC and LVRs. Table 7 summarizes the change in tap operations for substation LTC. For estimating the cost associated with the tap operation, it is assumed that increase/decrease in tap operation has a proportional effect on the maintenance and the lifetime of these devices. Based on the cost estimates from the report by Quanta Technology titled: System-Wide Impact Study for Interconnection of Photovoltaic Distributed Generation (PV-DG), page 65, it is assumed that each tap operation has an associated cost of \$1.00. Estimated change in LTC operations are monetized using the cost estimate or each operation, and the results are shown in table 7. The results indicate that change in operation in these devices compared to the base case causes a marginal increase in avoided operation of LTC.

Table 7: LTC operation and estimated avoided cost

Year	LTC Operation (Base Case)	LTC Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	880	880	0	0
1	902	860	42	42
2	916	934	-18	-18
3	934	1096	-162	-162
4	950	1330	-380	-380
5	966	1612	-646	-646
6	970	1634	-664	-664
7	988	1648	-660	-660
8	1002	1664	-662	-662
9	1014	1680	-666	-666
10	1020	1678	-658	-658

3.2.3 Feeder Equipment Service Life

As the simulations indicate, PV also decreases LVR operation at moderate levels and then increases them (Fig. 14). Table 8 summarizes the results for this case. Change in LVR operations are monetized using the same approach as in scenario I, and the results are placed in Table 8. The results indicate that change in operation in these devices compared to the base case is similar to that of scenario I, there is a marginal increase in avoided operation of LVR.

Table 8: LVR operation and estimated avoided cost

Year	Total LVR Operation (Base Case)	Total LVR Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	1572	1572	0	0
1	1612	1268	344	344
2	1640	1412	228	228
3	1682	1910	-228	-228
4	1708	2548	-840	-840
5	1718	3434	-1716	-1716
6	1726	3526	-1800	-1800
7	1746	3592	-1846	-1846
8	1760	3662	-1902	-1902
9	1796	3736	-1940	-1940
10	1816	3724	-1908	-1908

The cost associated with CAP switching has not been monetized, as we do not have a good cost estimate for this component, and it is expected that it will be not be considerable.

3.2.4 Distribution System Power Loss

To quantify this component, estimates of the total power loss reduction on the feeder due to PV from have been obtained from the simulations. To monetize the associated benefit, it is assumed that marginal cost of power savings is 3.22 cents per kWh [https://bit.ly/2SARXPp]. Table 9 shows the cost estimates obtained for the sample case.

Table 9: Cost of avoided loss due to PV

Year	Total Loss (MWh) (Base Case)	Total Loss (MWh) (PV)	Avoided Losses (MWh)	Avoided Losses ($)
0	98.98	98.98	-	-
1	97.53	90.48	7.05	226.96
2	96.09	88.46	7.63	245.67
3	94.70	93.53	1.17	37.73
4	93.34	111.13	-17.79	-572.84
5	92.04	140.67	-48.63	-1,565.95
6	90.70	140.30	-49.60	-1,597.04
7	89.47	139.92	-50.45	-1,624.33
8	88.26	139.57	-51.31	-1,652.32
9	87.04	139.24	-52.19	-1,680.59
10	85.88	138.93	-53.05	-1,708.19

3.2.5 Feeder Upgrade

Simulations indicated that PV does not cause overloads up to moderate levels of PV penetration (70-90%); very high penetration levels of PV can cause line overloads. Table 10 shows the overloads for the case with PV, and the cost associated with upgrading these sections to prevent overloading. For the cost estimate, the estimates reported in [https://www.nrel.gov/ docs/fy18osti/70710.pdf, page 19] is adopted; it is assumed that cost of the conductor upgrade for a 3-phase system is $130/ft. Since there are no overloads in the base case but overloads in the cases with with PV penetration, it is deemed that PV does not help defer line upgrades on the feeder. Regarding the cost associated with the new line overloads, it must also be noted that some of these upgrades may have already been considered during PV interconnection studies, and hence it is deemed that there is no avoided cost of service for this component.

Table 10: Cost of upgrades - case with PV

With PV				
Year	Equipment	Length/Rating	Unit Cost $/unit	Total Cost ($ x10^3)
5	'l115'	0.4 kft	130	52.0
5	'l3'	0.3 kft	130	39.0
5	'l7'	0.2 kft	130	26.0
5	'l10'	0.3kft	130	39.0
5	'l52'	0.2 kft	130	26.0
5	'l116'	0.4 kft	130	52.0

3.2.6 Total Cost of Service

Using these results, we can determine the Total Cost of Service of service PV provides for each year considered. The figures below show these results, which are the yearly avoided costs. Note that the total avoided cost is the sum of avoided cost estimates, and thus, positive value indicates benefits and negative value indicates cost.

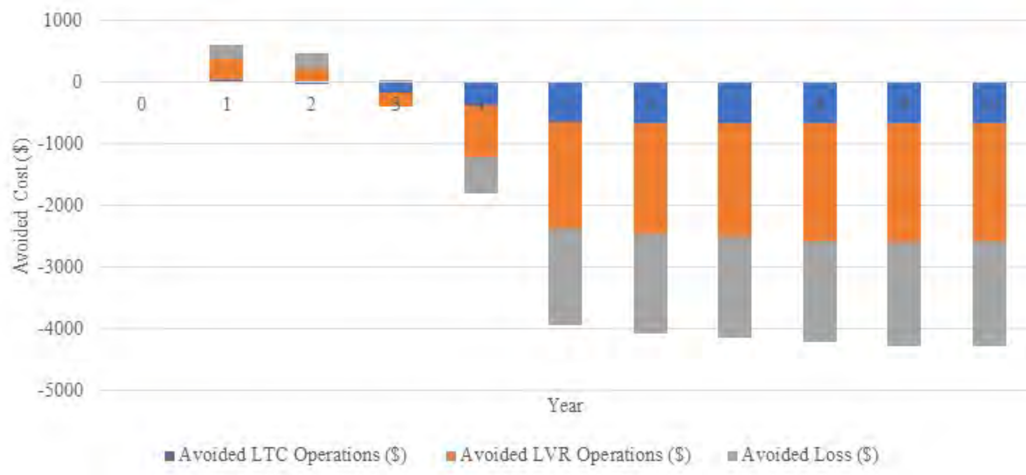

Figure 20: Avoided Cost of Service Per-Year: Case 1, Load Growth I

3.3 Observations for Scenario I

The results from this sample case indicate that:

1. PV provides peak load reduction at the substation up to 90% PV penetration. However, at higher penetrations we see considerable reverse power flow at the substation and peak demand exceeding that of the base case.
2. PV causes a sharp increase in the operations of LTCs and LVRs at higher penetration levels.
3. PV can cause overloading on the feeder backbone if upgrades were not made during integration studies.
4. PV reduces power loses up to moderate penetrations, and causes an increase in system losses at higher penetrations.
5. PV impact on voltage violations are minimal, due largely to the good Volt-VAR compensation on the feeder.

3.4 Load growth scenario II

Peak Load Growth Rate 1%, Energy Growth Rate 0.6%
The same analysis was performed for the load growth case in scenario II. Only the key changes in results are shown below.

3.4.1 Substation Capacity Deferral

Figure 21 shows the peak demand (kVA) at the substation, we see an increasing trend due to positive peak load growth. The reduction in peak demand compared to the PV installed is about the same as in scenario I, 10% during the first three years. The increase in kVA with the high PV in year 4 and 5 is not as significant as in scenario I owing to the higher peak load growth rate, i.e. 9% vs 16% in scenario I.

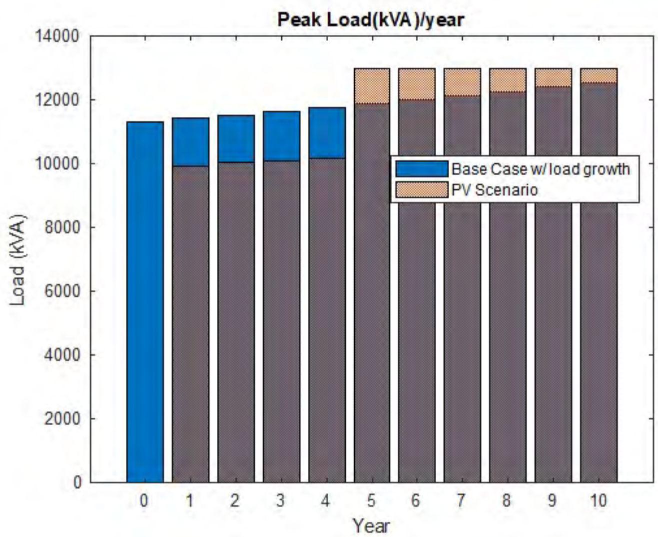

Figure 21: Yearly peak demand at substation - with and without PV

3.4.2 Distribution System Power Loss

Figure 22 shows the feeder power loss under this scenario. The results are similar to the previous one – marginal decrease in power loss up to moderate PV penetration (90%) and loss increases sharply at higher PV penetrations as in the previous case. However, we see an increasing trend in system losses as opposed to the decreasing trend due to increase load demand. For reference, the loss in the base case for year 0 is 99 MWh and year 10 is 114 MWh. While the losses in year 10 with PV amounts to 149 MWh, i.e. a 30% increase.

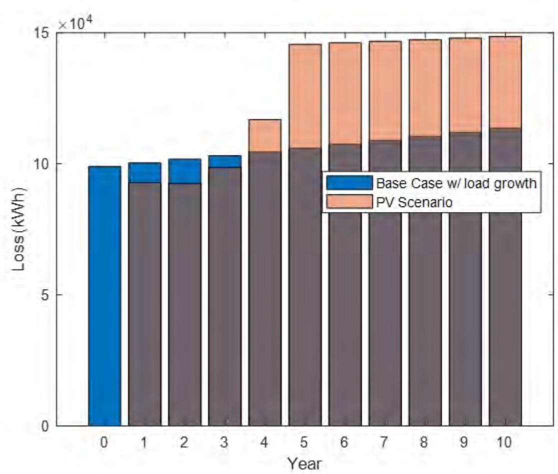

Figure 22: Yearly power loss in feeder - with and without PV

3.4.3 Feeder Upgrades

Feeder upgrades due to line and equipment overloads: Table 11 shows the line sections/equipment that were overloaded during the course of the 10 years. No overloads were detected in the base case. Figure 23 shows the line sections and equipment (highlighted in red) that are overloaded. In addition to the line sections, we see phase A of LVR 3 being overloaded in both cases as well.

Table 11: Thermal overload of line sections and equipment with PV

With PV						
Initial Overloading				Final Overloading		
Year	Equipment	% Max Loading	Duration (hours)	Year	% Max Loading	Duration (hours)
5	‘reg4a’	95.06	1.1	10	96.16	1.3
5	’l115’	100.9	12.63	10	100.67	11.5
5	’l3’	101.6	15.1	10	101.36	13.9
5	’l7’	101.7	15.45	10	101.45	14.25
5	’l10’	102.2	17.5	10	101.97	16.28

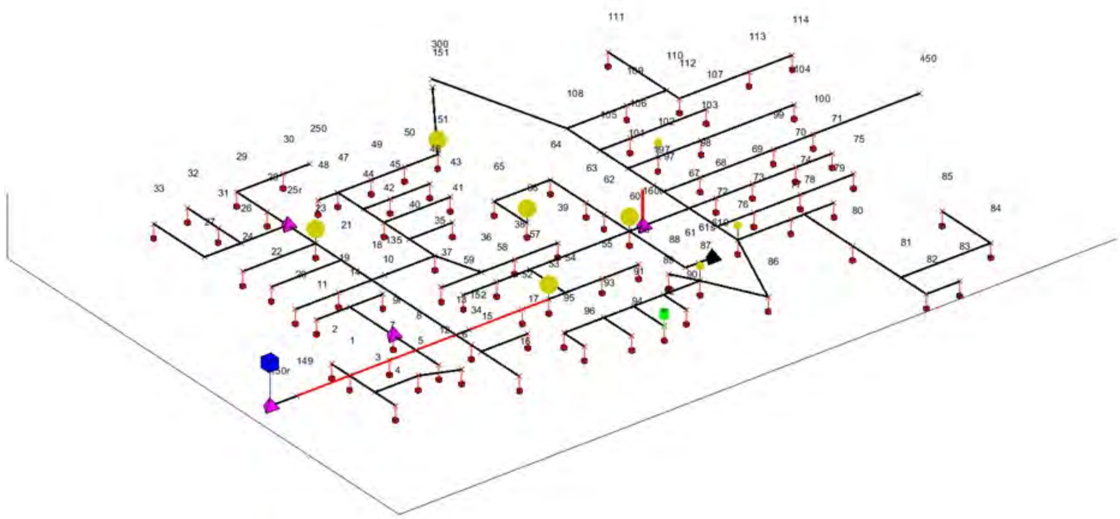

Figure 23: Equipment & line overload in year 5 with PV

Feeder upgrades due to voltage violations As in the previous case, no change in voltage violations were observed.

3.5 Cost Estimate for Service Components

3.5.1 Substation Equipment Service Life

As in previous case, PV decreases LTC operation at moderate levels and then increases them. Table 12 summarizes the results. Change in LTC operations are monetized using the same approach as in scenario I, and the results are placed in table 12. Results indicate that change in operation in these devices compared to the base case is similar to that of scenario I, there is a marginal increase in avoided operation of LTC.

Table 12: LTC operation and estimated avoided cost

Year	LTC Operation (Base Case)	LTC Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	880	880	0	0
1	908	868	40	40
2	914	942	-28	-28
3	932	1126	-194	-194
4	960	1346	-386	-386
5	984	1632	-648	-648
6	1022	1658	-636	-636
7	1048	1664	-616	-616
8	1072	1684	-612	-612
9	1104	1720	-616	-616
10	1124	1730	-606	-606

3.5.2 Feeder Equipment Service Life

As in previous case, PV decreases LVR operation at moderate levels and then increases them. Table 13 summarizes the results. Change in LVR operations are monetized using the same approach as in scenario I, and the results are placed in Table 13. Results indicate that change in operation in these devices compared to the base case is similar to that of scenario I, there is a marginal increase in avoided operation of LVR.

Table 13: LVR operation and estimated avoided cost

Year	Total LVR Operation (Base Case)	Total LVR Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	1572	1572	0	0
1	1654	1284	370	370
2	1686	1412	274	274
3	1770	1908	-138	-138
4	1838	2516	-678	-678
5	1898	3434	-1536	-1536
6	1984	3484	-1500	-1500
7	2038	3476	-1438	-1438
8	2086	3540	-1454	-1454
9	2158	3632	-1474	-1474
10	2222	3654	-1432	-1432

Capacitor operations are shown in table 14 but they have not been monetized as in the previous case.

Table 14: Capacitor operations

Year	Total CAP Operations (Base Case)	Total CAP Operations (with PV)	Avoided Operations
0	62	62	0
1	76	24	52
2	72	16	56
3	90	36	54
4	88	152	-64
5	104	290	-186
6	108	292	-184
7	114	298	-184
8	124	304	-180
9	124	312	-188
10	120	312	-192

3.5.3 Distribution System Power Loss

The results for avoided losses due to PV are shown in table 15. Compared to scenario I, we see similar pattern that of the previous scenario: PV lowers the power loss up to moderate levels (90%) and then the loss increases at higher levels.

Table 15: Cost of avoided loss due to PV

Year	Total Loss (MWh) (Base Case)	Total Loss (MWh) (PV)	Avoided Losses (MWh)	Avoided Losses ($)
0	98.98	98.98	–	–
1	100.34	92.83	7.51	241.72
2	101.74	92.48	9.26	298.32
3	103.12	98.65	4.46	143.70
4	104.55	116.85	-12.31	-396.30
5	105.99	145.58	-39.59	-1,274.71
6	107.45	146.13	-38.68	-1,245.48
7	108.94	146.70	-37.76	-1,215.94
8	110.44	147.31	-36.86	-1,187.03
9	111.98	147.91	-35.93	-1,157.10
10	113.55	148.52	-34.97	-1,126.09

3.5.4 Feeder Upgrades

As in scenario I, our simulations indicated that there were line/equipment overloads during the 10-year period. The results from table 11 are monetized below. There rate for a single phase 5MVA LVR is considered to be $40,000. Since there is no accepted way for monetizing this component, this component has not been included in the total cost of service calculations and in not considered in subsequent feeder configurations.

Table 16: Cost of upgrades - case with PV

With PV				
Year	**Equipment**	**Length/Rating**	**Unit Cost $/unit**	**Total Cost ($ x10^3)**
5	‘reg4a’	5 MVA	40k	40.0
5	’l115’	0.4 kft	130	52.0
5	’l3’	0.3 kft	130	39.0
5	’l7’	0.2 kft	130	26.0
5	’l10’	0.3 kft	130	39.0

3.5.5 Total Cost of Service

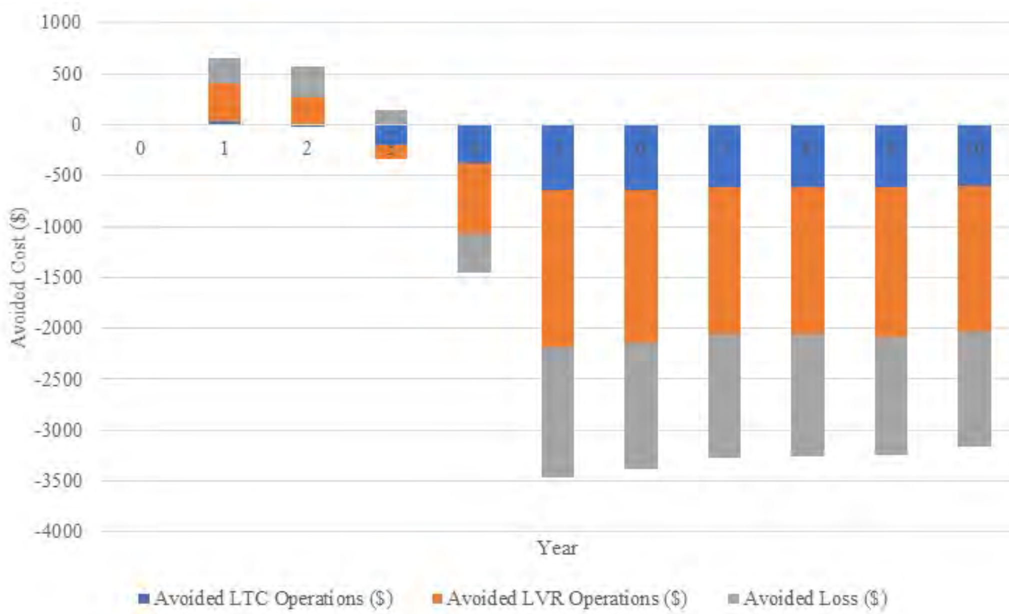

Figure 24: Total Avoided Cost of Service Per-Year: Case 1, Load Growth II

3.6 Observations on Scenario II

The results from this scenario II indicate that:

1. The instances of line and equipment upgrades are higher in scenario I than scenario II. since the overloads are caused by PVs, their extent is less in scenario II due to the higher peak growth rate.

2. The extent of reverse power flow is not significantly different from scenario I.

3. Utility scale PV causes a sharp increase in the operations of LTCs and LVRs at higher penetration levels (100% or higher), similar to what is seen in scenario I.

4. Cost of avoided losses is similar to that of the scenario I; marginal decease in losses up to moderate levels of PV and then losses increase at higher PV levels.

5. Similar to scenario I, no voltage violations were observed.

4 Simulation Results - Case II

As in previous case, simulations have been performed under the two different load growth scenarios.

4.1 Load growth scenario I

Peak Load Growth rate 0.21%, Energy Growth -1.02%

The results obtained from simulations are summarized below. The summary compares the change in each metric considered as PV penetration increases over the planning period.

4.1.1 Substation Capacity Deferral

Comparing the substation peak demand (kVA) in the base case and the case with PV, we do not see any significant increase or decrease in peak substation loading, unlike the results seen in case 1.

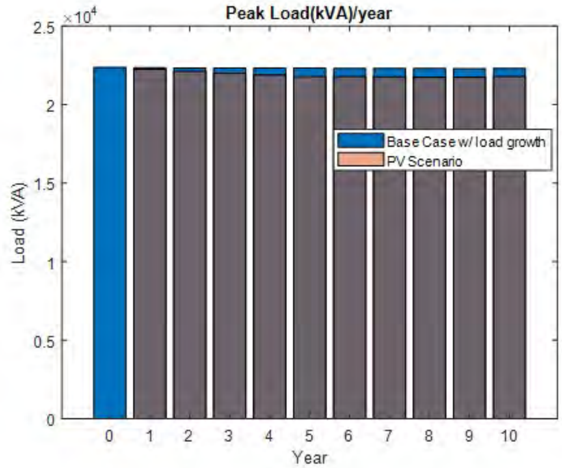

Figure 25: Yearly peak demand at substation - with and without PV

Feeder-wise demand reduction However, when we look at the feeder-wise results in the figure below, we see that there in an increase in J1's peak demand after year 4, and almost an exponential increase in the peak demand of IEEE 123 PV from year 3 onward. IEEE 123 No PV expectedly has no change in its peak demand. Since the PV penetrations of both the feeders are the same, the trend in both J1 and IEEE 123 PV also appear similar. Also, we do not see an overall increase in peak demand at the substation since each of the feeders considered peaks at different times As such, the contribution from PV in reducing (or increasing) the substation peak demand is negligible and will not defer any capacity.

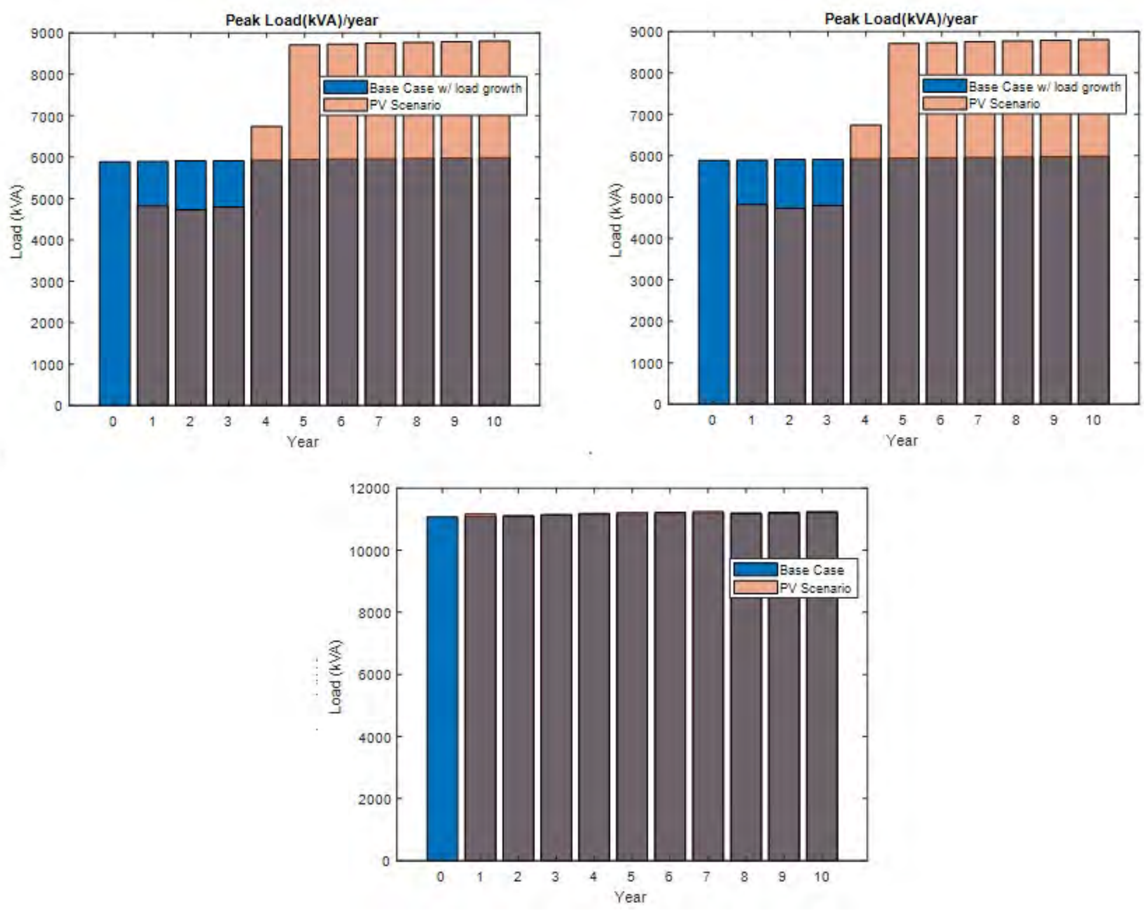

Figure 26: Feeder-wise yearly peak demand - with and without PV, Top Left: J1, Top Right: IEEE 123 PV, Bottom: IEEE 123 No PV

Furthermore, the results in figure 27 and 28 show the real power (kW) demand at the substation for the case without and with PV on phase A for year 10, respectively. We see that the peak demand (kW) remains almost the same ($\tilde{7}$.5MW) in winter (Jan-Feb), while the reverse power flow is prominent during spring and fall. The results of the other phases, while not shown here, follow a similar trend.

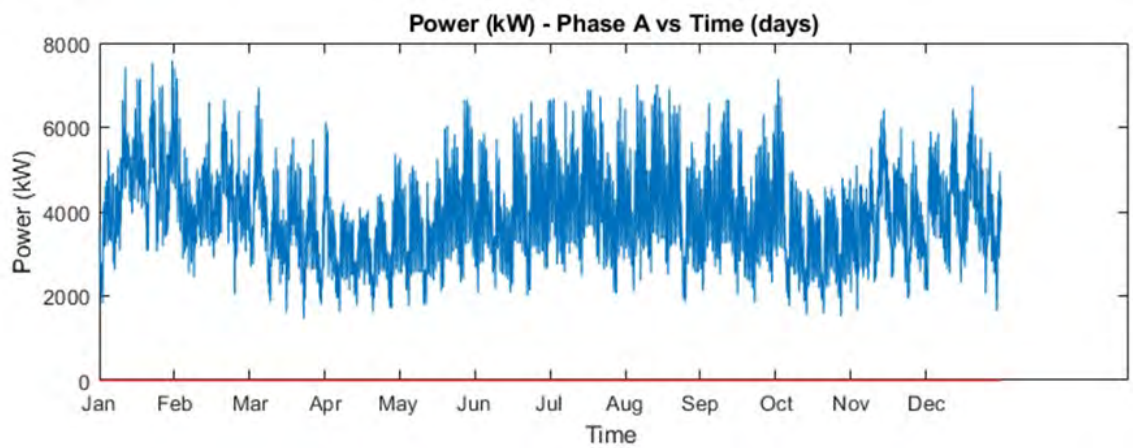

Figure 27: Net load at substation during year 10 without PV

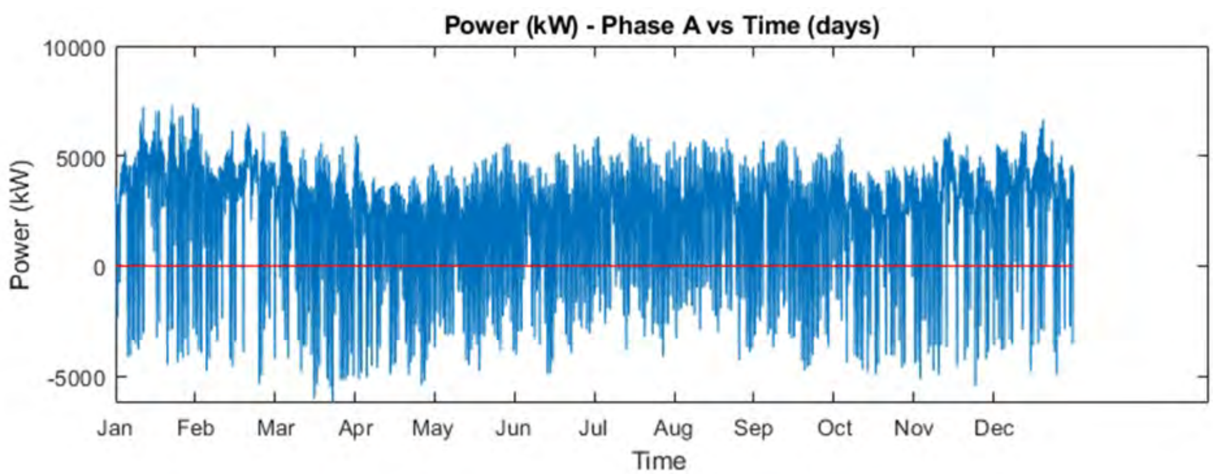

Figure 28: Net load at substation during year 10 with PV

The figure below shows the total kVA demand profile during year 10 for both cases - without and with PV. It appears that this circuit is a winter peaking one and the addition of PV has only served to reduce the average loading of the transformer(14MVA to 9.8MVA) while not affecting the original winter peak.

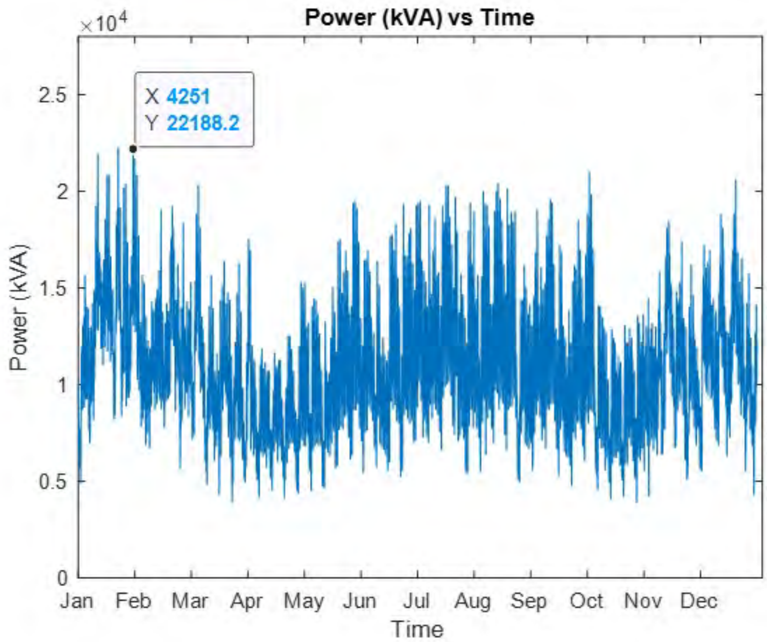

Figure 29: Net load profile year 10 - base case (No PV)

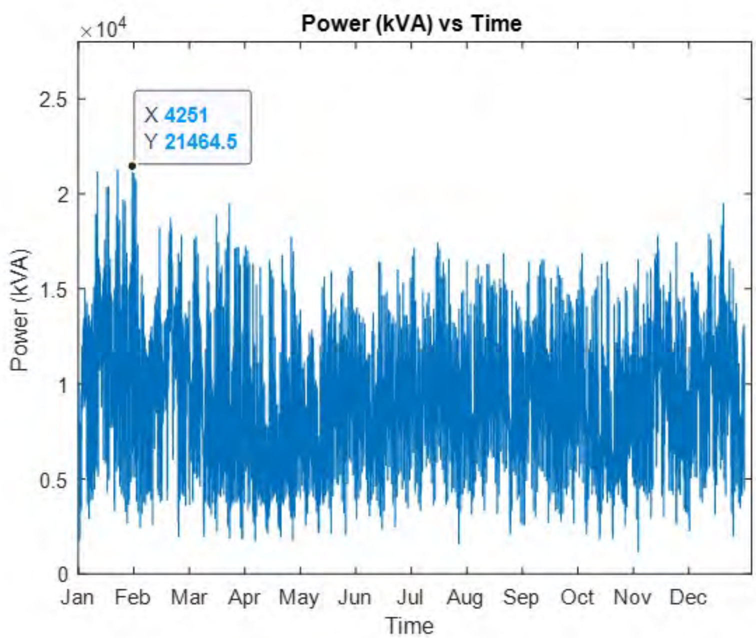

Figure 30: Net load profile year 10 - with PV

4.1.2 Substation Equipment Service Life

OLTC Operation: The figure below shows the OLTC operation for the analysis period. We do not see a significant change in operations as compared to case 1.

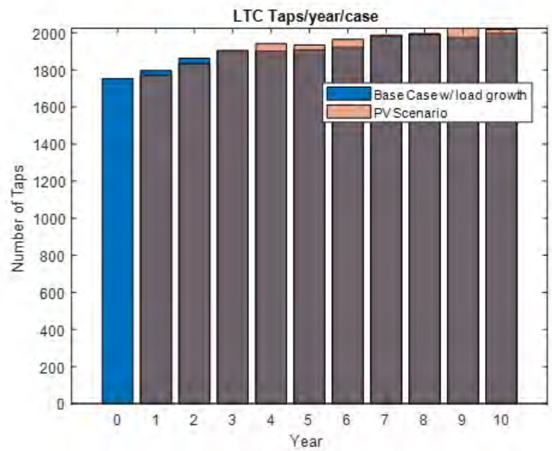

Figure 31: OLTC operations per year with and without PV

Transformer Loading: The results for the transformer loss of life(LOL) are shown in the figure below. Compared to the results in case 1, we see that the base case has a greater impact on LOL as the average transformer loading as a percentage of transformer capacity is higher in case 2 than in case 1. This result also shows a greater benefit due to PV; it may be recalled that the average loading on the substation transformer in case 1 does not decrease to the same extent as in this case.

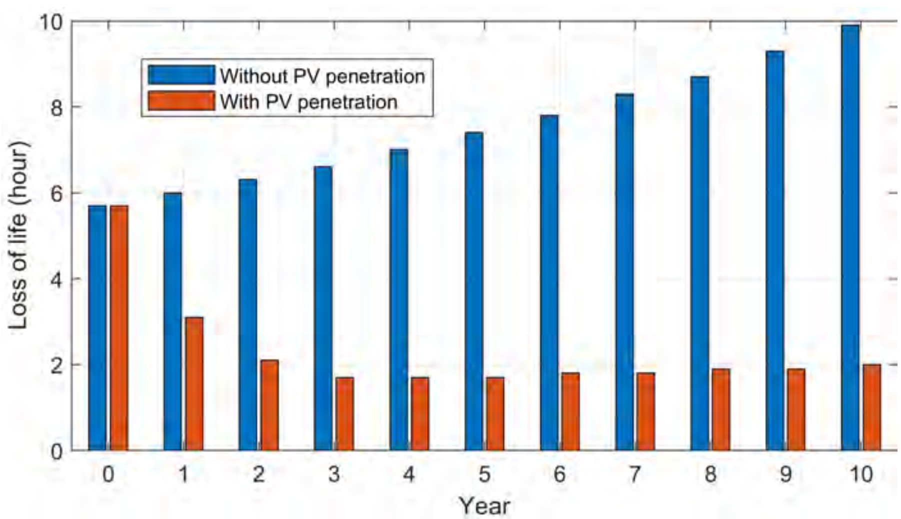

Figure 32: Comparison of transformer loss of life, with and without PV penetration

4.1.3 Feeder Equipment Service Life

The results of the impact on feeder equipment are shown in figures 33, 34, and 35. For the J1 feeder, we see that increasing PV penetration causes some increase in the two regulators immediately downstream from the last PV farm, after year 4. In IEEE 123 PV, we see that the increase in PV penetration has caused a considerable increase in LVR operations across all regulators, in some as early as year 1. The most dramatic increase occurs around year 5. In IEEE 123 No PV, which does not have any PV installed on it, we see an increase in two phases of a downstream regulator, which could imply that LVRs on feeders without PV can experience an increase in operations due to the PV on the other system. However, as we see in other feeder configurations, this is not always true; this is a phenomenon unique to this feeder configuration.

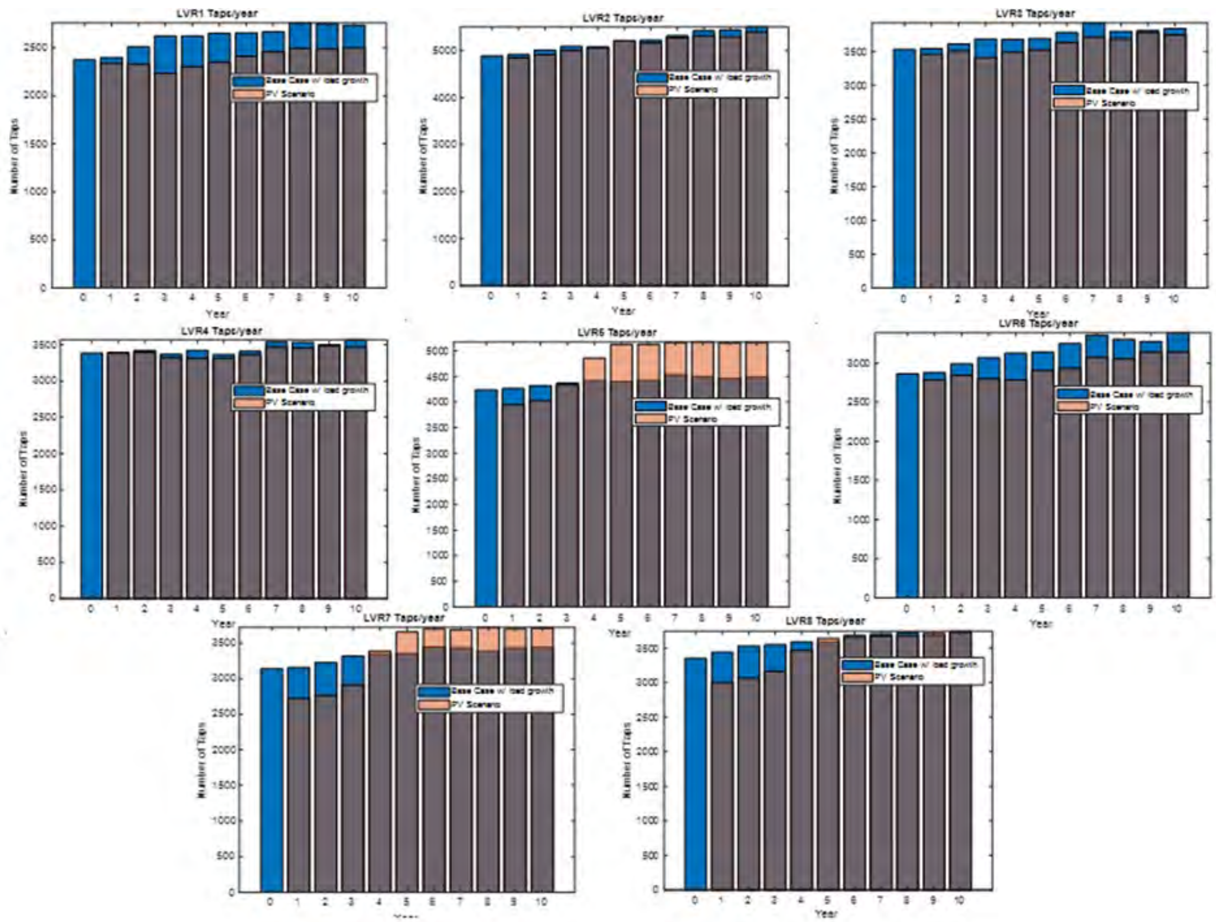

Figure 33: J1 - LVR operations per year with and without PV

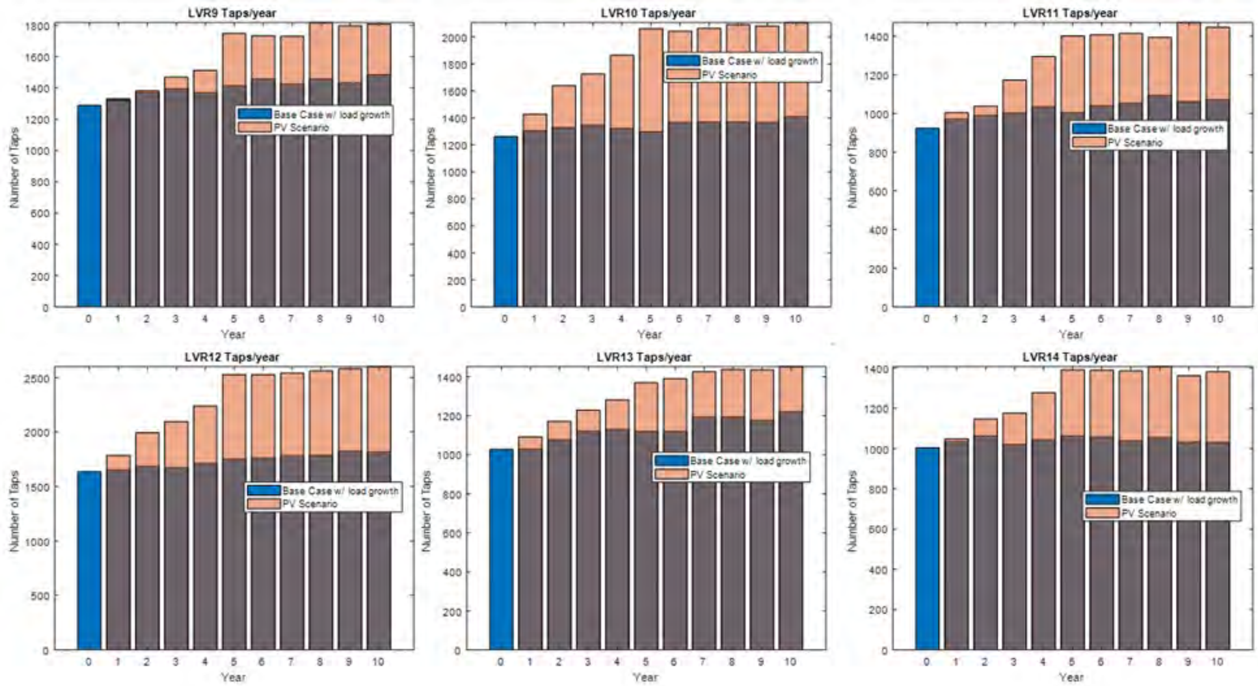

Figure 34: IEEE 123 PV - LVR operations per year with and without PV

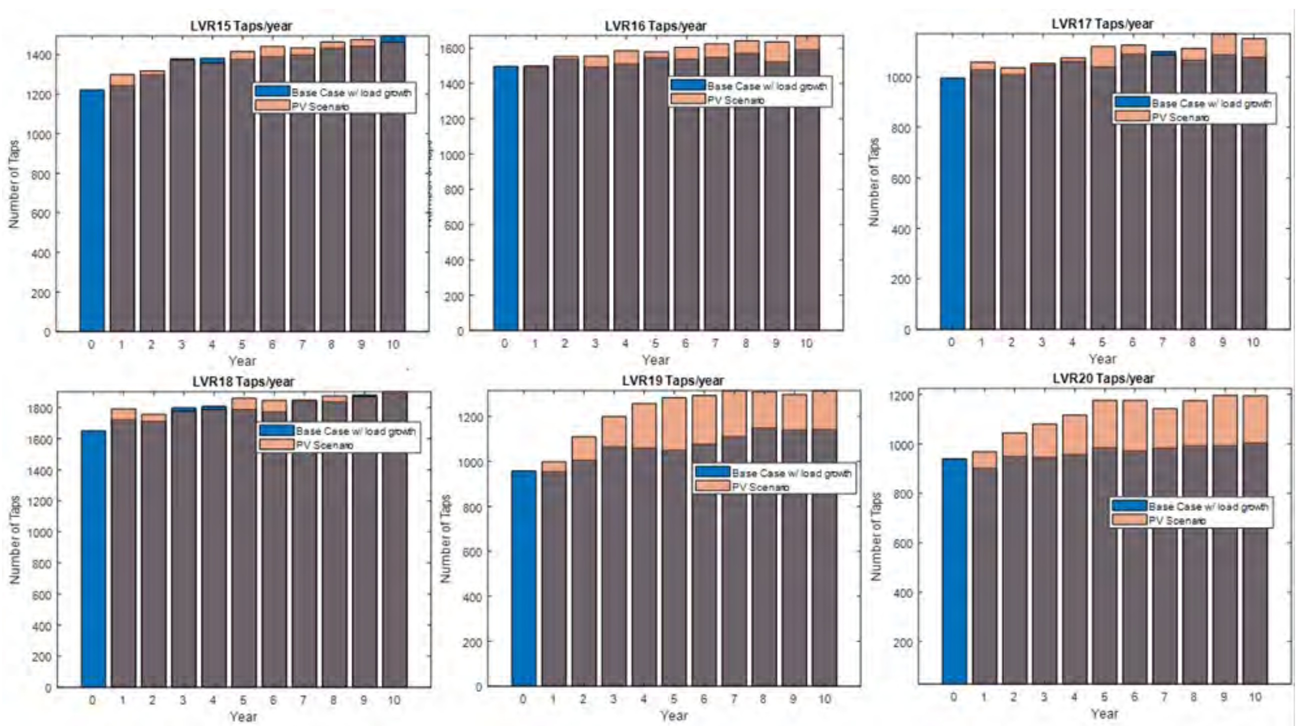

Figure 35: IEEE 123 No PV - LVR operations per year with and without PV

The figure below shows the change in CAP Bank switching as PV penetration increases on the system under consideration. No consistent or discernable trend is observed. Also, as stated earlier, since the cost of capacitor operations is not monetized due to its low value, this component is ignored.

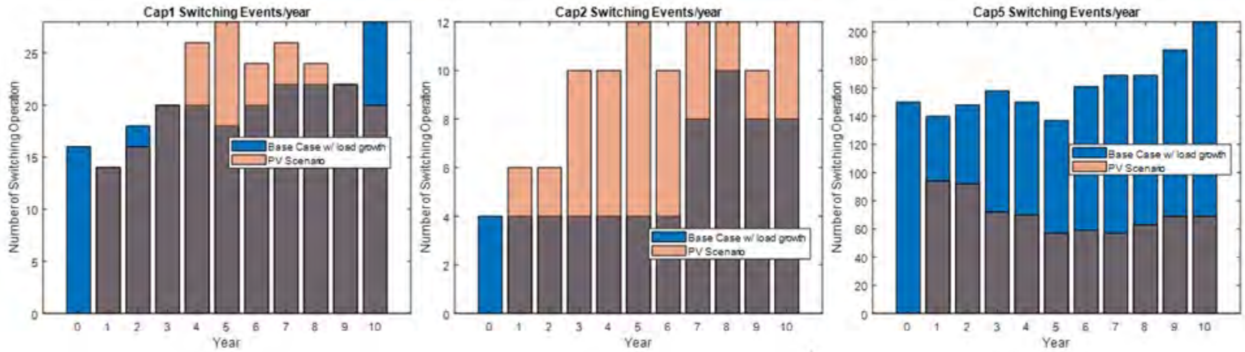

Figure 36: J1 - Capacitor switching per year - with and without PV

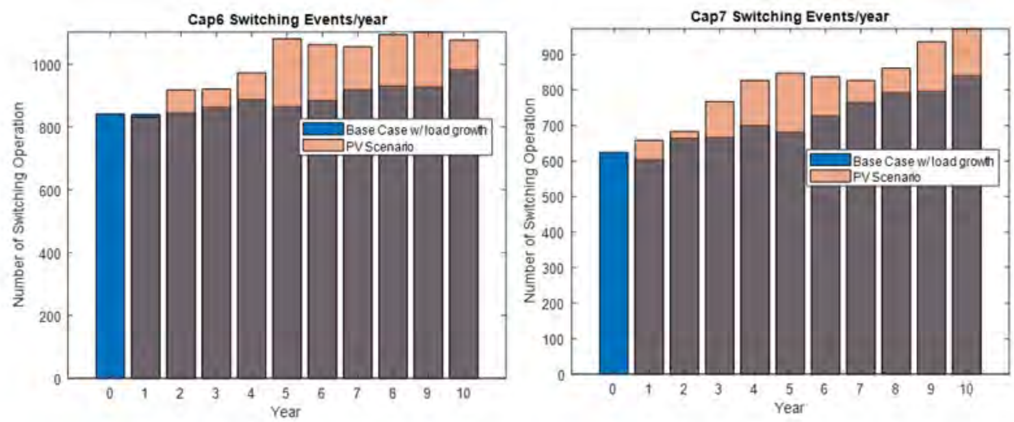

Figure 37: Capacitor switching per year - with and without PV - Left: IEEE 123 PV, Right: IEEE 123 No PV

4.1.4 Distribution System Power Loss

Figure 38, shows the results for total distribution system loss over the simulation period. We see that there is an initial, although marginal decrease in system losses at lower penetrations up to year 3 followed by a reversal in trends. Looking at the disaggregated results helps further explain this result.

Looking at the results in figure 39, we see a steep decrease in the losses in the substation area (mainly transformer), this is due to the reduced average loading as pointed out earlier. IEEE 123 No PV has no change in overall losses as expected. Both feeders with PV experience an initial reduction in losses up to year 2 followed by a reversal in trends. J1 experiences some increase in losses starting from year 4. IEEE 123 PV has the most increase in system losses after year 4. Since the reduction in system losses in the substation in larger in comparison to the increase in losses on the individual feeders, the overall trend shows an initial reduction that tapers off in year 5.

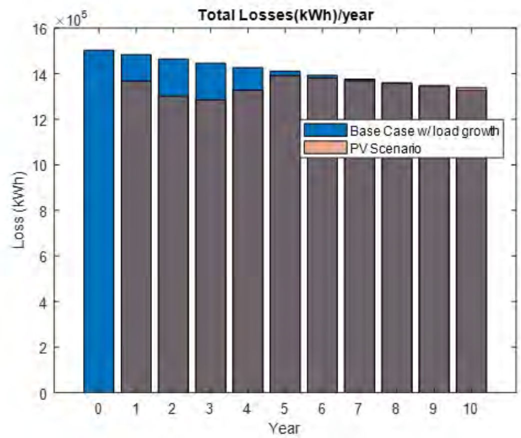

Figure 38: Total distribution system losses per year - with and without PV

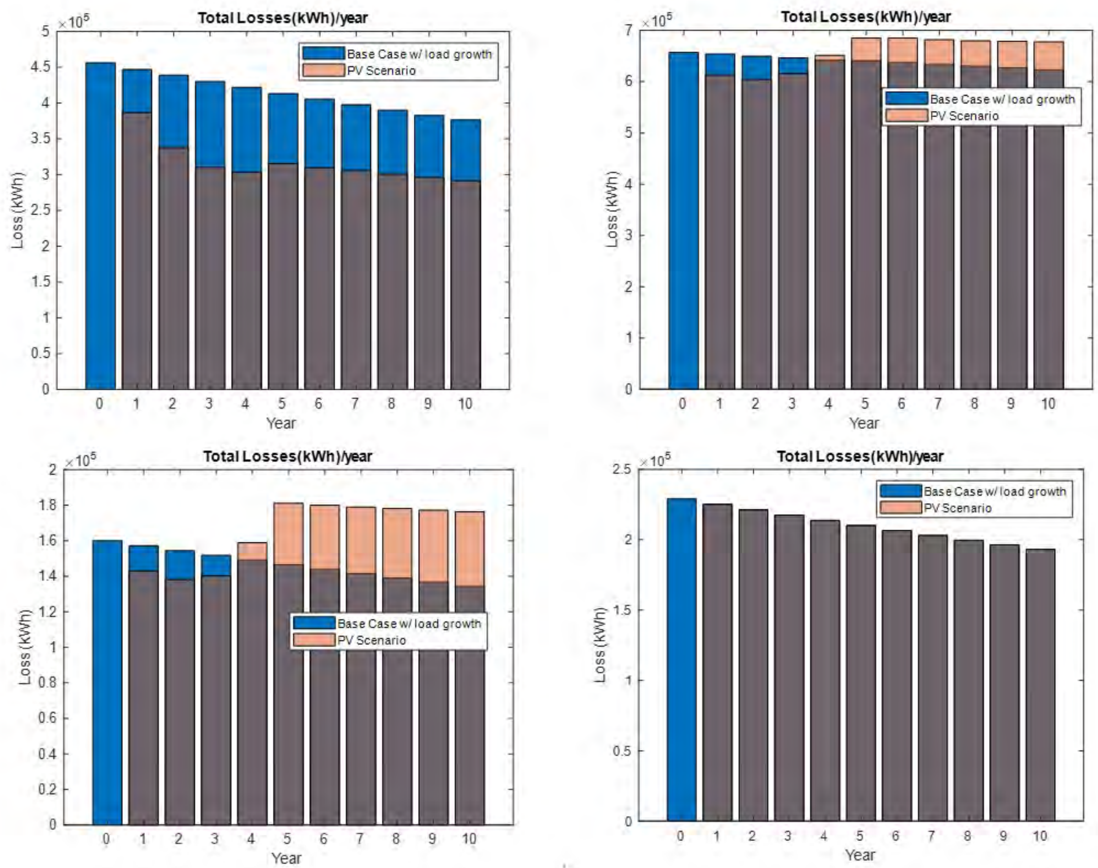

Figure 39: Feeder-wise losses per year - with and without PV, Top Left: Substation Area, Top Right: EPRI - J1, Bottom Left: IEEE 123 PV, Bottom Right: IEEE 123 No PV

4.1.5 Feeder Upgrades

Feeder Upgrades due to Voltage Violations

As in the previous case, the IEEE 123 Node feeder does not suffer from voltage issues with integrated PV. Figure 40 shows maximum and minimum voltage profiles on the J1 feeder with and without PV. We see that the J1 feeder experiences high voltage issues at very high PV penetration (200%). Also, the minimum voltage on this feeder while low, does not go below 0.95 Vpu. It is worth noting that these results are corroborated by the fact that this feeder is known to have low and high voltage issues based on EPRI's own study [1].

In this case, a mitigation method needs to adopted to avoid the overvoltages. Enabling PV inverters with Volt/VAR and Volt/WAtt capability is an option that recently became available. As in previous case, in this study the mitigation measures are not considered, as they are assumed to be undertaken during PV integration stage.

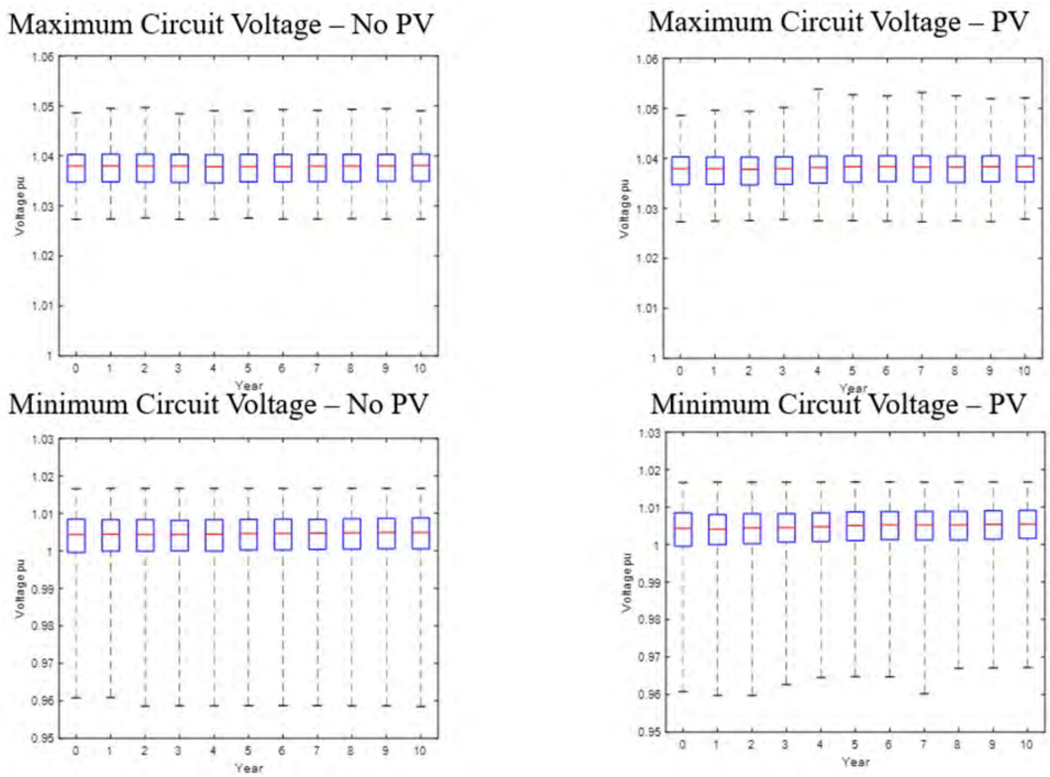

Figure 40: J1 - Voltage Statistics - with and without PV

4.2 Cost Estimate for Service Components

4.2.1 Substation Capacity Deferral

Based on the results in figure 25, it was noted that no significant reduction or increase in substation loading occurred during the analysis period. Hence, no capacity deferral or increase is considered.

4.2.2 Substation Equipment Service Life

The results in table 17 show the monetized value of avoided LTC operations. In contrast to the results in case 1, we do not see a significant change in LTC operations.

Table 17: LTC operation and estimated avoided cost

Year	LTC Operation (Base Case)	LTC Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	1,752	1,752	0	0
1	1,796	1,770	26	26
2	1,862	1,834	28	28
3	1,900	1,904	-4	-4
4	1,902	1,942	-40	-40
5	1,907	1,933	-26	-26
6	1,923	1,965	-42	-42
7	1,979	1,987	-8	-8
8	1,995	1,991	4	4
9	1,975	2,025	-50	-50
10	1,997	2,017	-20	-20

4.2.3 Feeder Equipment Service Life

Compared to the LTC operations, the LVR operations have increased especially after year 4. This increase in operations has been monetized in table 18.

Table 18: Total LVR operations and estimated avoided cost

Year	Total LVR Operation (Base Case)	Total LVR Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	42,171	42,171	0	0
1	42,652	41,785	867	867
2	43,643	43,022	621	621
3	44,359	44,093	266	266
4	44,672	46,325	-1,653	-1653
5	44,835	48,666	-3,831	-3831
6	45,505	48,966	-3,461	-3461
7	46,326	49,540	-3,214	-3214
8	46,442	49,858	-3,416	-3416
9	46,324	50,130	-3,806	-3806
10	46,943	50,347	-3,404	-3404

The unmonetized results for capacitor operations are shown in Table 19. While the disaggreagted values showed no particular trend, we see that the maximum increase in capacitor operations occurred in year 5, the year with maximum PV, which seemingly tapers off in the next few years. However, this trend is not consistent.

Table 19: Capacitor Operations

Year	Total CAP Operations (Base Case)	Total CAP Operations (with PV)	Avoided Operations
0	1,636	1,636	0
1	1,602	1,603	-1
2	1,680	1,716	-36
3	1,712	1,790	-78
4	1,762	1,906	-144
5	1,705	2,025	-320
6	1,797	1,993	-196
7	1,883	1,978	-95
8	1,924	2,055	-131
9	1,942	2,140	-198
10	2,066	2,150	-84

4.2.4 Distribution System Power Loss

Table 20 presents the monetized values for total distribution system power loss. We see that there is a noticeable reduction in system losses during the first few years while PV penetration is below 100 percent, up to year 4, followed by a reversal, finally culminating in an increase in losses.

Table 20: Cost of avoided loss due to PV

Year	Total Loss (MWh) (Base Case)	Total Loss (MWh) (PV)	Avoided Losses (MWh)	Avoided Losses ($)
0	1,502.62	1,502.62	0.00	0
1	1,483.10	1,367.61	115.49	3718.81
2	1,463.91	1,301.63	162.27	5225.25
3	1,445.64	1,283.88	161.76	5208.81
4	1,426.56	1,327.48	99.08	3190.51
5	1,410.41	1,391.86	18.56	597.597
6	1,392.86	1,381.35	11.51	370.778
7	1,376.41	1,369.25	7.16	230.541
8	1,359.68	1,358.16	1.53	49.1349
9	1,342.72	1,348.25	-5.53	-178.04
10	1,327.28	1,338.57	-11.29	-363.43

4.2.5 Total Cost of Service

Using the results presented above, the total cost of service provided by PV for each year in the analysis period is shown in figure 41.

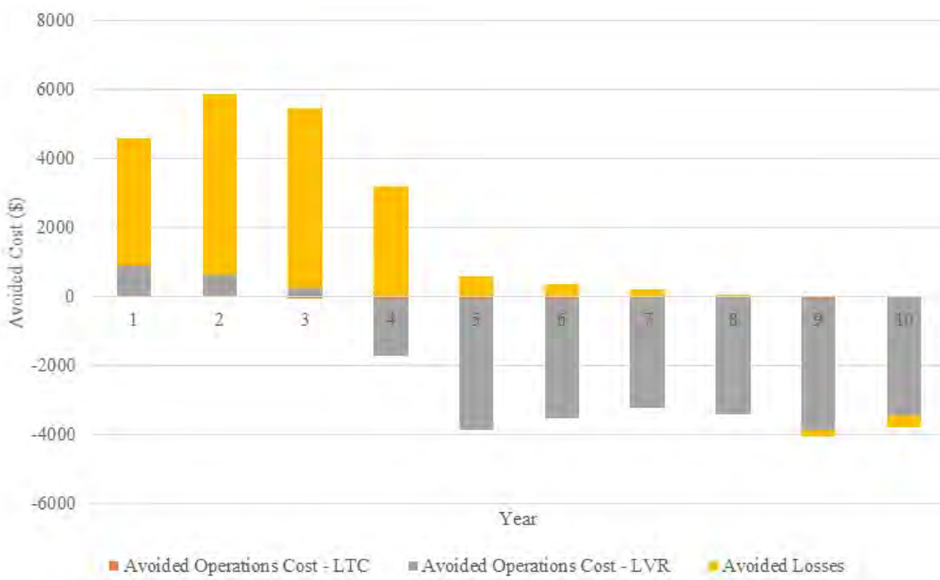

Figure 41: Total Avoided Cost of Service Per-Year: Case 2, Load Growth I

4.3 Observations for Scenario I

The results from this sample case indicate that:

1. PV does not significantly change the maximum demand experienced by the substation
2. While PV does not cause a marked change in LTC operations, we see a significant increase in LVR operations especially after year 4.
3. PV at lower penetrations has resulted in significant decrease in system losses, particularly in the substation transformer.
4. Voltage constrained feeder may experience voltage violations at very high penetrations.

4.4 Load growth scenario II

Peak Load Growth Rate 1%, Energy Growth Rate 0.6%
The same analysis was performed for the load growth case in scenario II. Only the key changes in results are shown below.

4.4.1 Substation Capacity Deferral

The trend in peak demand (kVA) as seen in figure 42 is similar to scenario I; there is a minor reduction in peak loading.

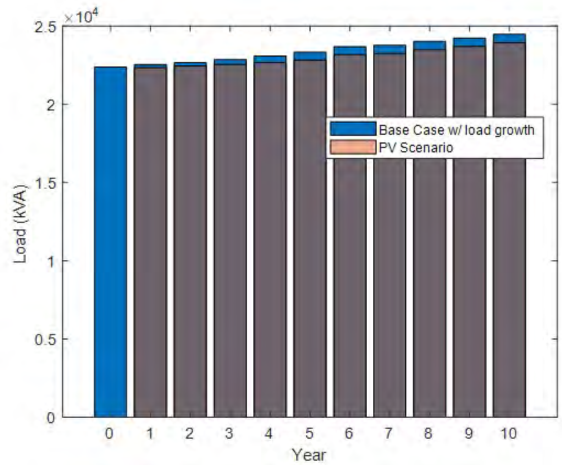

Figure 42: Yearly peak demand at substation - with and without PV

Feeder-wise demand reduction:

Looking at the results in figure 43, we see the peak demand on J1 and IEEE 123 PV have both increased due the PV and saturated in year 5, this increase is less when compared to scenario I due to the higher peak load (and energy) growth rate. Expectedly, No change in IEEE 123 No PV is observed.

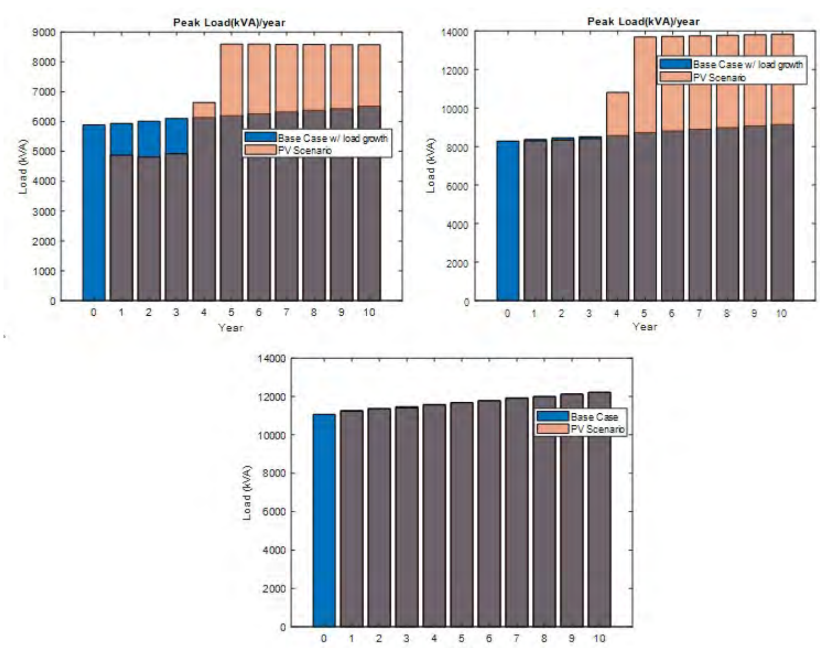

Figure 43: Feeder-wise yearly peak demand - with and without PV, Top Left: J1, Top Right: IEEE 123 PV, Bottom: IEEE 123 No PV

4.4.2 Distribution System Power Loss

The results for the total and feeder-wise system losses are shown in figures 44 and 45. The reduction in distribution system losses is more significant in scenario II compared to scenario I as some of the increase in individual feeder losses caused by PV is offset by the higher peak (and energy) growth rate.

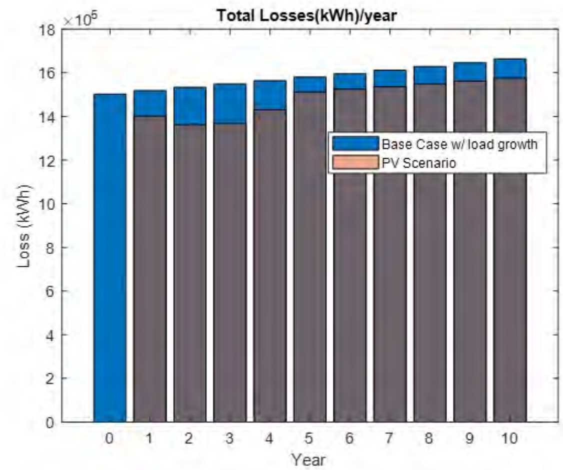

Figure 44: Total losses per year - with and without PV

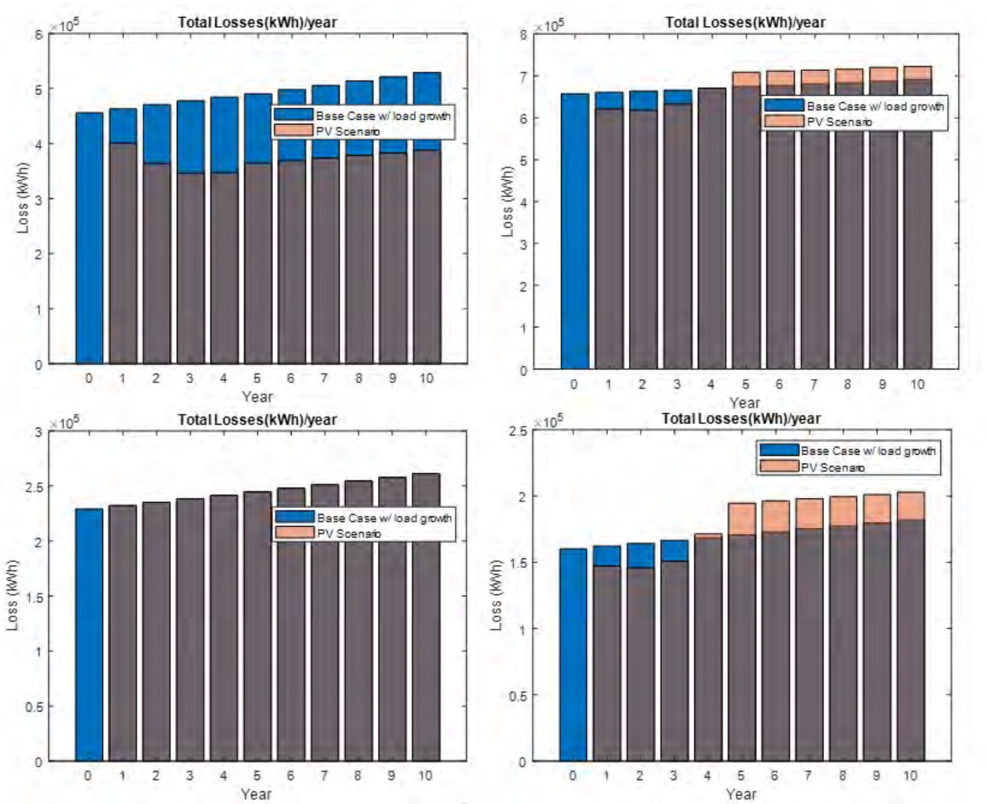

Figure 45: Feeder-wise total losses per year - with and without PV, Top Left: Substation, Top Right: J1, Bottom Left: IEEE 123 No PV, Bottom Right: IEEE 123 PV

4.4.3 Feeder upgrades

Upgrades due to line section and equipment overloads:
This component has not been considered as no case of PV deferring upgrades was observed.

Upgrades due to voltage violations:
Voltage violations similar to those seen in scenario I, were observed in scenario II on J1 – after year 5. These can be addressed by using Volt/VAR and Volt/Watt control on the utility scale inverters.

4.5 Cost Estimate for Service Components

4.5.1 Substation Equipment Service Life

Table 21 presents a summary of the monetized value of LTC operations. As in scenario I, the increase – or decrease in year 1 and 2 – is not significant.

Table 21: LTC operation and estimated avoided cost

Year	LTC Operation (Base Case)	LTC Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	1,752	1,752	0	0
1	1,781	1,768	13	13
2	1,812	1,818	-6	-6
3	1,868	1,920	-52	-52
4	1,896	1,992	-96	-96
5	1,956	2,026	-70	-70
6	1,984	2,042	-58	-58
7	2,016	2,096	-80	-80
8	2,061	2,117	-56	-56
9	2,119	2,171	-52	-52
10	2,155	2,223	-68	-68

4.5.2 Feeder Equipment Service Life

Table 22 shows the results for this scenario. There is a steady increase in LVR operations observed from year 3, preceded by a reduction in LVR operations in year 1 and 2. The increase in LVR operations is noticeably lower than that of scenario I as a result of the higher load growth offsetting some of the impacts of PV.

Table 22: Total LVR operations and estimated avoided cost

Year	Total LVR Operation (Base Case)	Total LVR Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	42,171	42,171	0	0
1	42,979	41,271	1,708	1708
2	43,495	42,509	986	986
3	44,378	45,186	-808	-808
4	45,264	47,227	-1,963	-1963
5	45,913	49,383	-3,470	-3470
6	46,737	49,643	-2,906	-2906
7	47,671	50,528	-2,857	-2857
8	48,453	50,611	-2,158	-2158
9	48,704	51,635	-2,931	-2931
10	50,019	52,522	-2,503	-2503

The results for total capacitor operations are shown in the table below. While the increase in switching operations are not monetized, it is noted that the increase follows the trend of increasing PV peneration.

Table 23: Capacitor Operation

Year	Total CAP Operations (Base Case)	Total CAP Operations (with PV)	Avoided Operations
0	1,636	1,636	0
1	1,570	1,578	-8
2	1,596	1,598	-2
3	1,688	1,748	-60
4	1,724	1,746	-22
5	1,774	1,866	-92
6	1,748	1,922	-174
7	1,782	1,910	-128
8	1,805	1,956	-151
9	1,805	1,945	-140
10	1,859	1,949	-90

4.5.3 Distribution System Power Loss

As stated earlier, due to the higher load growth rate, PV is able to avoid a higher proportion of system losses in comparison to scenario I. In fact, we do not have the reversal in trends that was seen in scenario I. Avoided losses increase upto year 3, followed by a sharp decrease in year 5.

Table 24: Cost of avoided loss due to PV

Year	Total Loss (MWh) (Base Case)	Total Loss (MWh) (PV)	Avoided Losses (MWh)	Avoided Losses ($)
0	1,502.62	1,502.62	0.00	0
1	1,517.99	1,400.60	117.39	3779.86
2	1,533.10	1,362.12	170.98	5505.58
3	1,548.25	1,367.86	180.39	5808.58
4	1,563.99	1,430.49	133.50	4298.66
5	1,580.69	1,512.54	68.16	2194.61
6	1,596.08	1,524.57	71.51	2302.67
7	1,612.41	1,536.69	75.72	2438.06
8	1,628.80	1,548.69	80.10	2579.31
9	1,646.04	1,561.79	84.25	2713.00
10	1,663.40	1,574.23	89.18	2871.48

4.5.4 Total Cost of Service

In contrast to the cost of service results seen in scenario I, avoided losses continues to be a benefit for the entire analysis period. However, the trend in avoided operations cost for LVRs is similar to what is observed in scenario I.

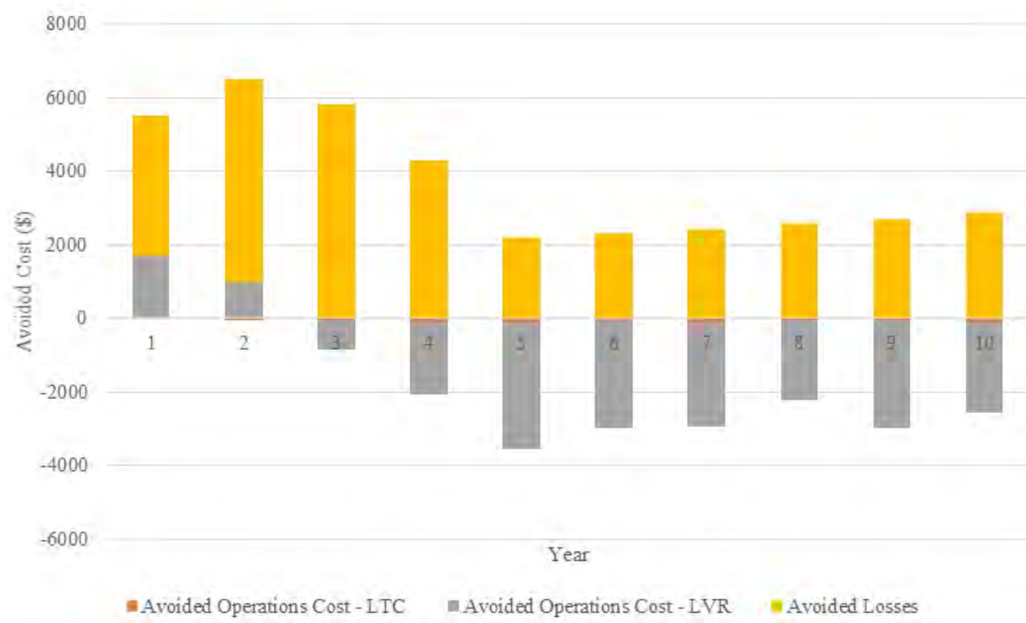

Figure 46: Total Avoided Cost of Service Per-Year: Case 2, Load Growth II

4.6 Observations on Case 2, Load Growth Scenario II

The results from this scenario II indicate that:

1. Similar to scenario I, PV does not cause a significant change in maximum demand at the substation
2. There is no significant increase in LTC operations; LVR operations, on the other hand, have increased, albeit not as much as in scenario I.
3. Avoided losses are always positive for the entire simulation period when compared to scenario I.

5 Simulation Results - Case 3

Similar to earlier cases, all simulations have been performed under the two different load growth scenarios.

5.1 Load growth scenario I

Peak Load Growth rate 0.21%, Energy Growth -1.02%

The results obtained from simulations are summarized below. The summary compares the change in each metric considered as PV penetration increases over the planning period.

5.1.1 Substation Capacity Deferral

Figure 47 shows the results for the peak demand at the substation. Similar to the results seen in case 2, we see no change in substation peak demand.

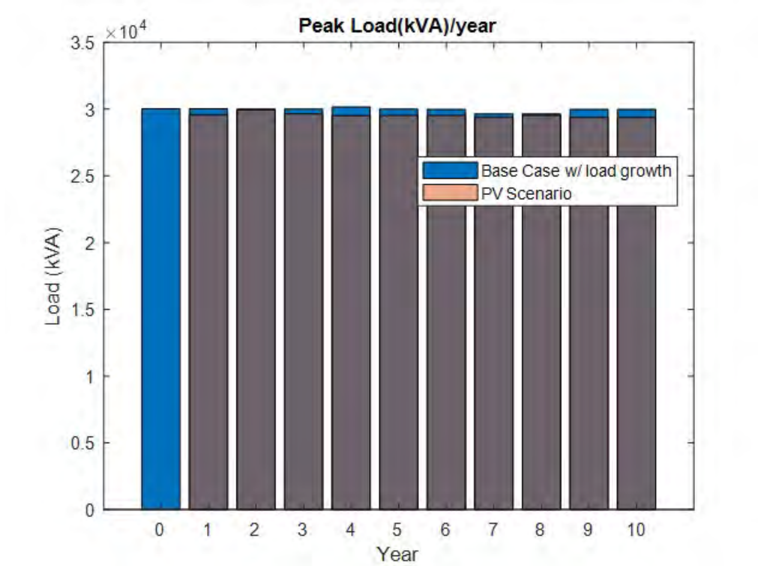

Figure 47: Yearly peak demand at substation - with and without PV

Feeder-wise demand reduction

Looking at the disaggregated results in figure 48, we see an initial decrease in peak demand on J1 feeder followed by a sudden increase in year 5. In the results for IEEE 123 PV1 and PV2 we do not see the initial decrease in the first few years. However, the peak demand in year 5 is significantly more than the base case, especially in IEEE 123 PV2.

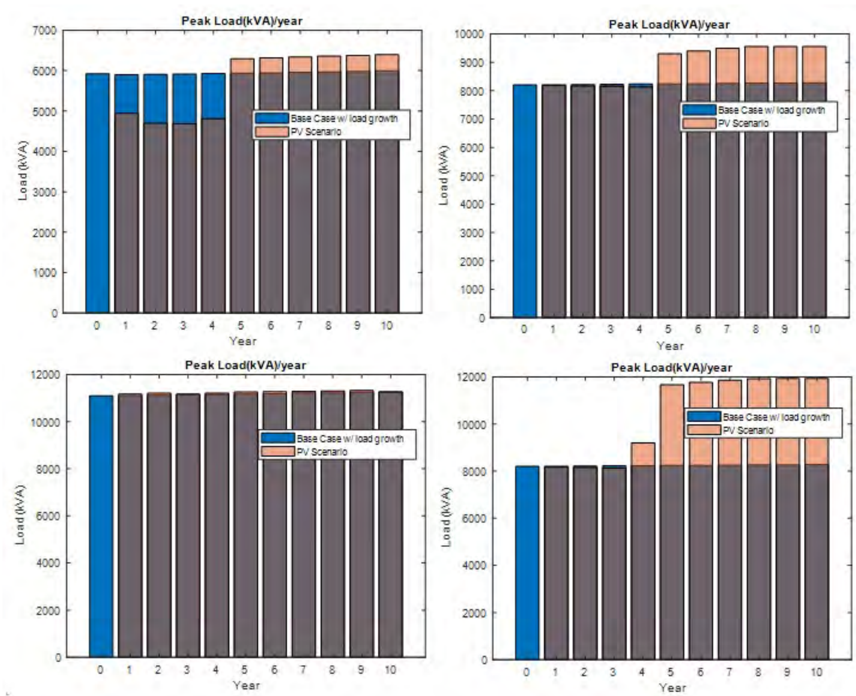

Figure 48: Feeder-wise yearly peak demand - with and without PV, Top Left: J1, Top Right: IEEE 123 PV, Bottom: IEEE 123 No PV

The figures below (49 and 50) show the yearly real power peak demand (kW) for year 10 of the analysis period without and with PV, for phase A, respectively. This distribution circuit is also winter peaking, as such the results follow those in case 2, where the increase in PV is not sufficient to increase the substation demand due to reverse power flow, which explains the results in figure 47.

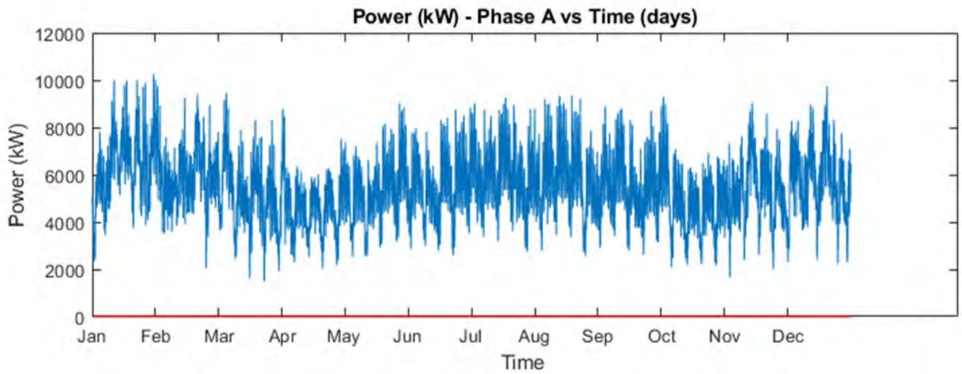

Figure 49: Net load at substation during year 10 without PV

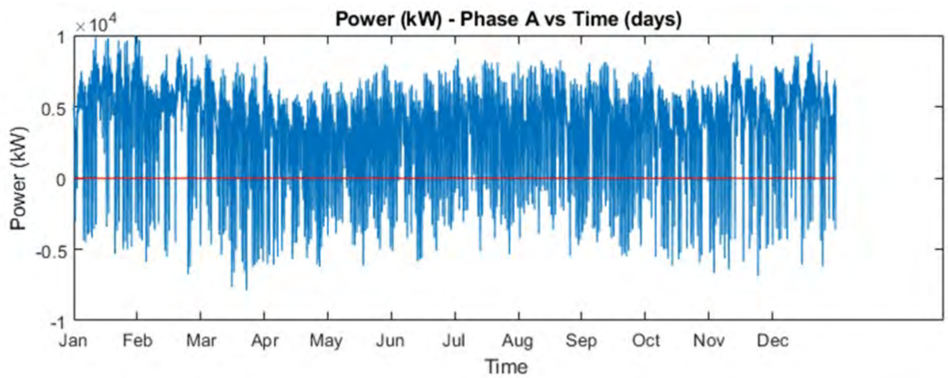

Figure 50: Net load at substation during year 10 with PV

Figures 51 and 52, show the total peak demand (kVA) for year 10 of the analysis period without and with PV, respectively. In this figure, we see more clearly that the increase in PV penetration only serves to decrease the average loading(18MVA to 14MVA) on the substation transformer but does not tangibly affect the system peak.

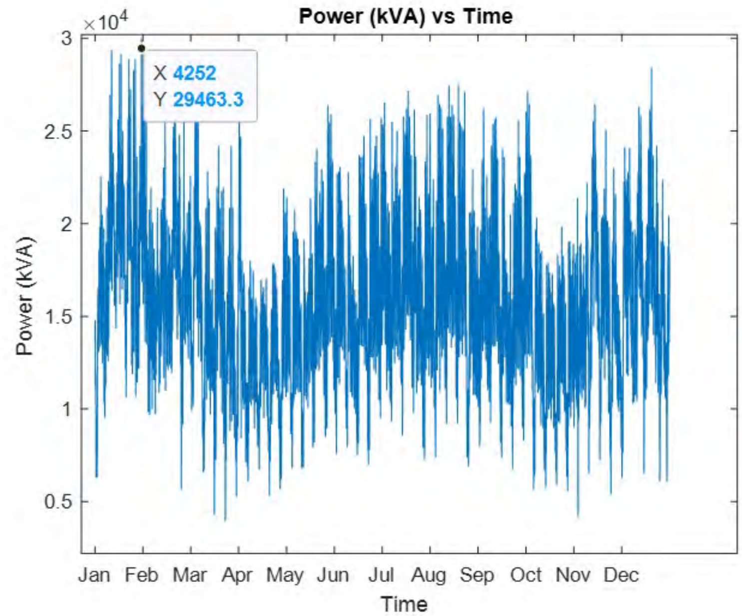

Figure 51: Net load profile year 10 - base case (No PV)

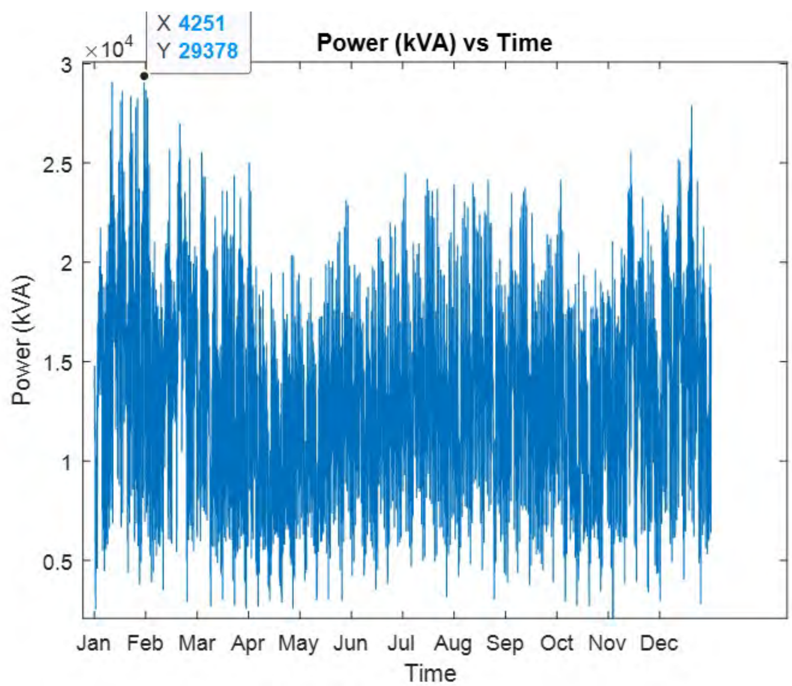

Figure 52: Net load profile year 10 - with PV

5.1.2 Substation equipment Service Life

OLTC Operation:
Compared to case 2, the results in figure 53 show a continuous increase in LTC operations right from year 1. Also, the increase stagnates in year 5.

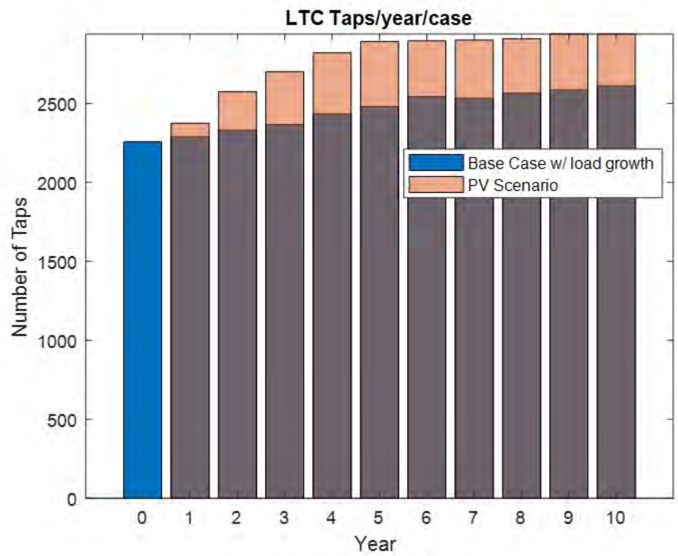

Figure 53: OLTC operations per year with and without PV

Transformer Loading: The results for transformer loss of life (LOL) are shown in the figure below. These results are similar to those seen in case 2. As pointed out earlier, since PV reduces the average loading on the substation transformer, it effectively reduces the loss of life experienced by the transformer. It must be noted that since the average loading is a higher fraction of transformer rating, we see a higher LOL in the base case and consequently a greater absolute reduction in LOL due to PV.

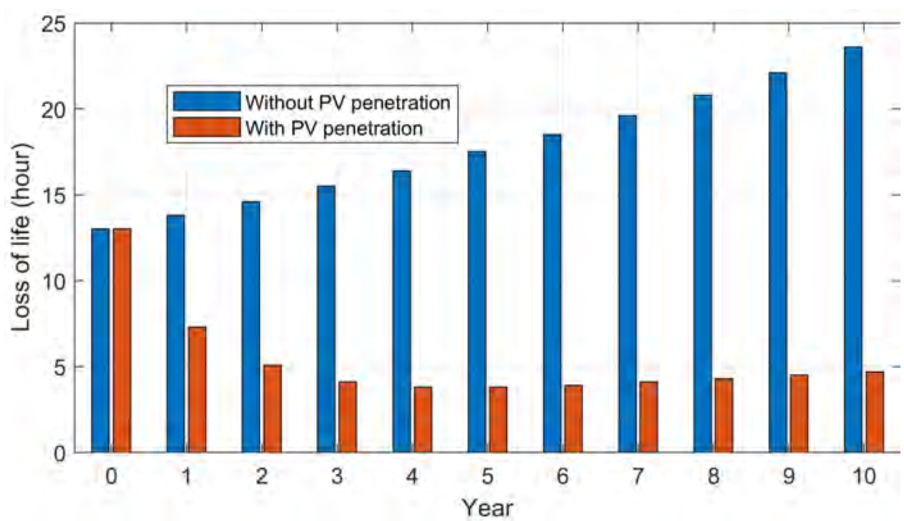

Figure 54: Comparison of transformer loss of live, with and without PV penetration

5.1.3 Feeder Equipment Service Life

Figures 55, 56, 57, and 58 show the operation of each feeder's LVRs. Since the penetration on J1 is reduced in comparison to case 2, the increase in LVR operations is also reduced.

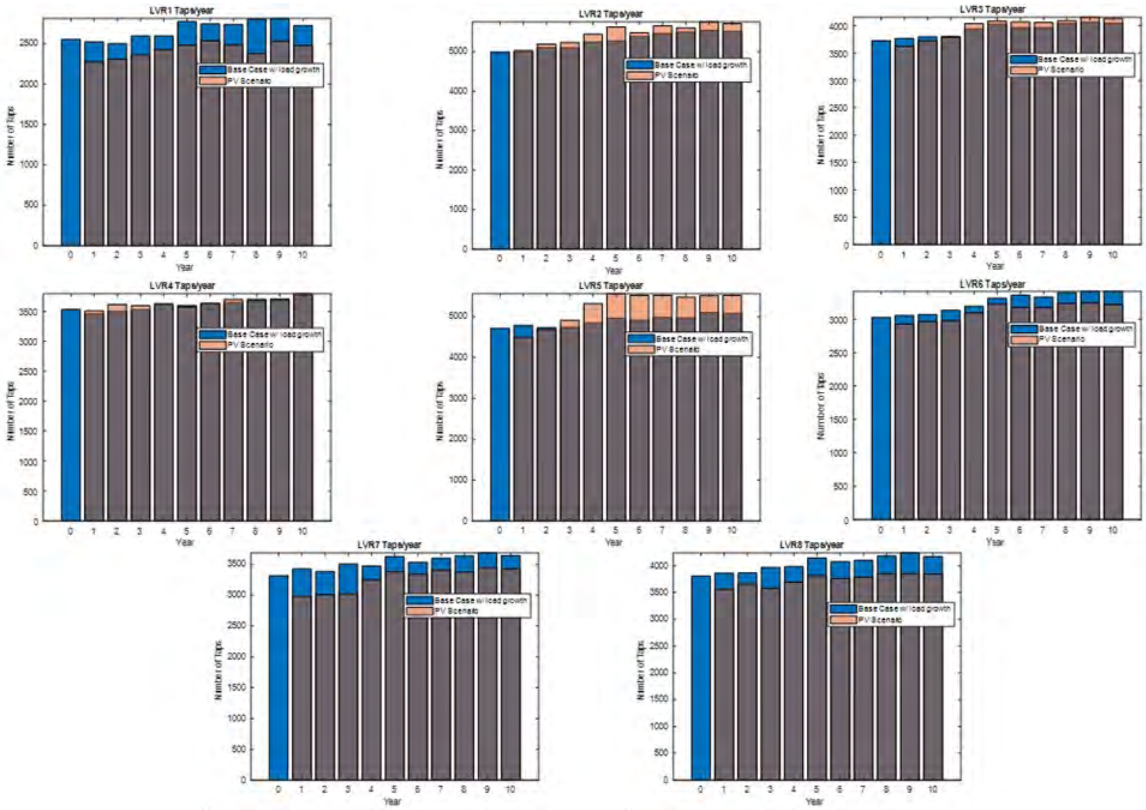

Figure 55: J1 - LVR operations per year with and without PV

The results for IEEE 123 PV1 show an increase in all LVR operations right from the beginning. This is also true for the LVRs in IEEE 123 PV2, although the increase in their operations is larger as the penetration of PV on the feeder is also higher.

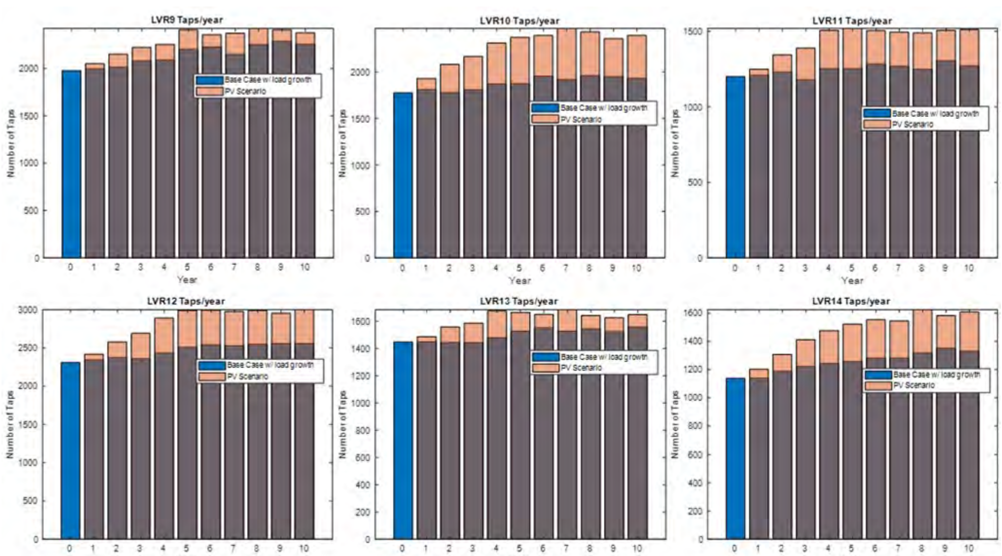

Figure 56: IEEE 123 PV1 - LVR operations per year with and without PV

Similar to what was observed in case 2, we see an increase in LVR operations in IEEE 123 No PV. However, since this is the same feeder that was used in case 3, other feeders need to be looked at to establish that this phenomenon is pervasive.

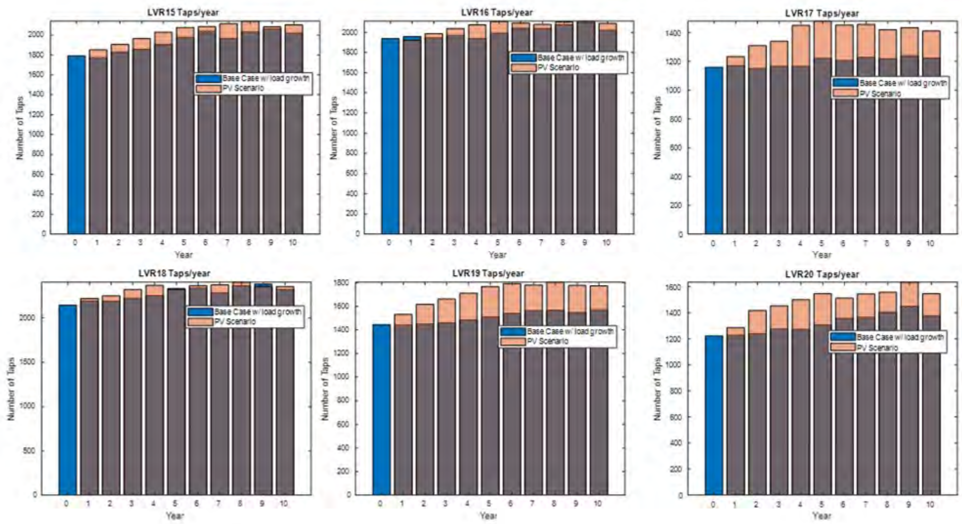

Figure 57: IEEE 123 No PV - LVR operations per year with and without PV

As pointed out earlier, the increase in LVR operations on IEEE 123 PV2, shown in the figure below, is larger due to the higher PV penetration in comparison to IEEE 123 PV1.

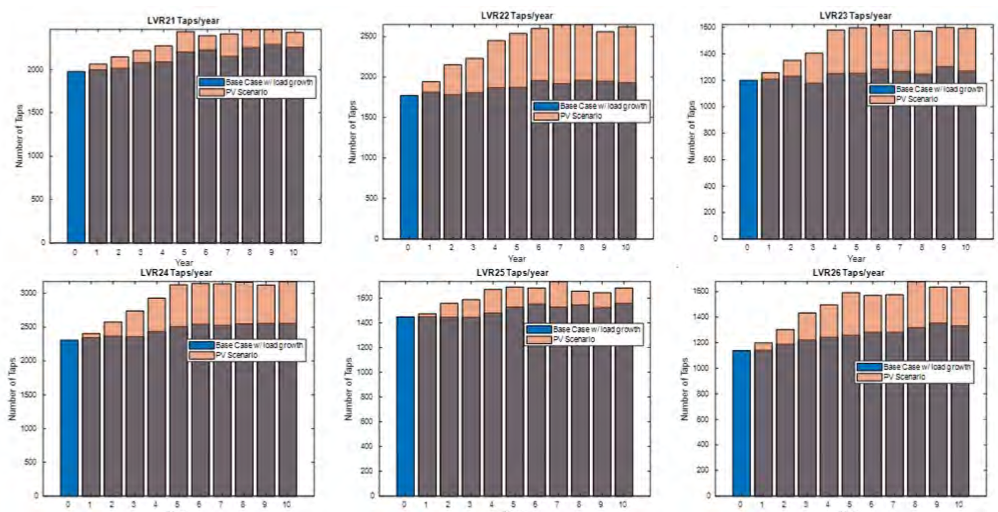

Figure 58: IEEE 123 PV2 - LVR operations per year with and without PV

The figure below shows the change in CAP Bank switching as PV penetration increases on the feeder. The IEEE feeders have some increase in capacitor operations, however, in the J1 feeder, we see a reduction in two of the 5 capacitors (two capacitors are in always on mode and are not shown). As in the previous case, these results will not be monetized.

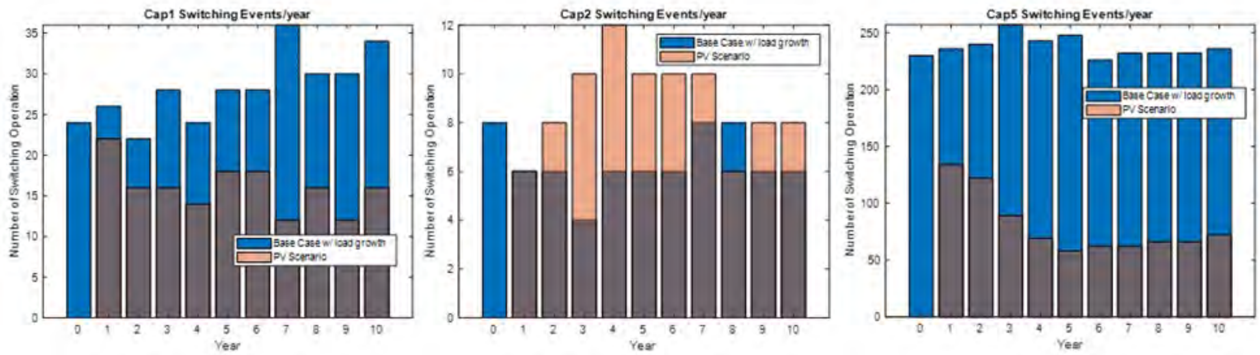

Figure 59: J1 - Capacitor switching per year - with and without PV

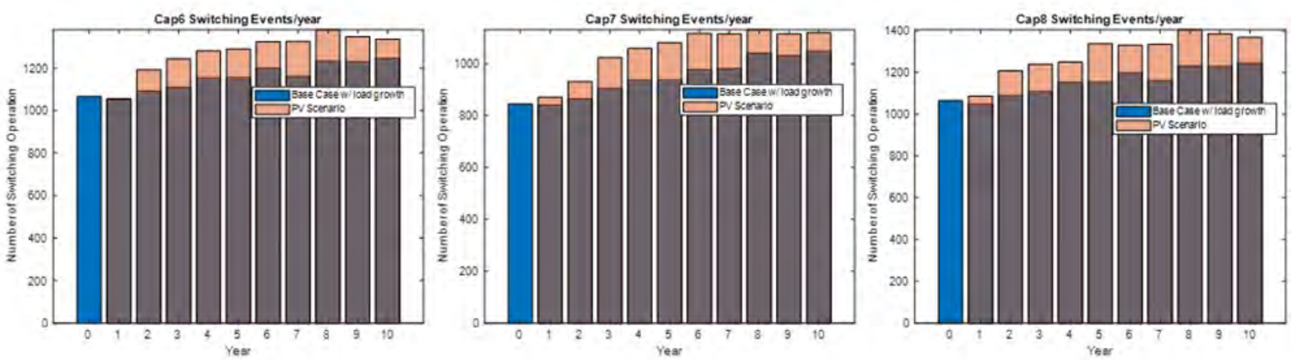

Figure 60: Capacitor switching per year - with and without PV - Left: IEEE 123 PV1, Middle: IEEE 123 No PV, Right: IEEE 123 PV2

5.1.4 Distribution System Power Loss

Figure 61 shows the power loss (kWh) across the entire distribution system and solely at the substation, while figure 62 shows the same result on a feeder basis. Similar to the results in case 2, we see a general reduction in overall system losses. Also, we do not see the increase in overall losses that is seen in case 2. Most of the loss reduction comes from the lower loading on the substation transformer compared to the base case.

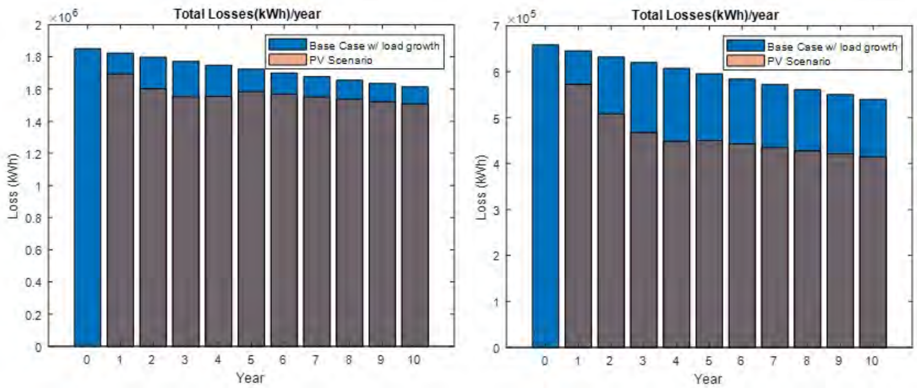

Figure 61: Total losses per year - with and without PV, Left: Total Distribution System, Right: Substation Area

Since the PV penetration on all the feeder is lower than the pv penetration in case 2, we see that there is no increase in losses on J1 and IEEE 123 PV1. However, there is a some increase in losses on IEEE 123 PV2. The maximum reduction in system losses (overall) occurs in year 3, followed by a reversal in trend which stops at year 5, afterwhich avoided losses gradually decrease, while still remaining positive.

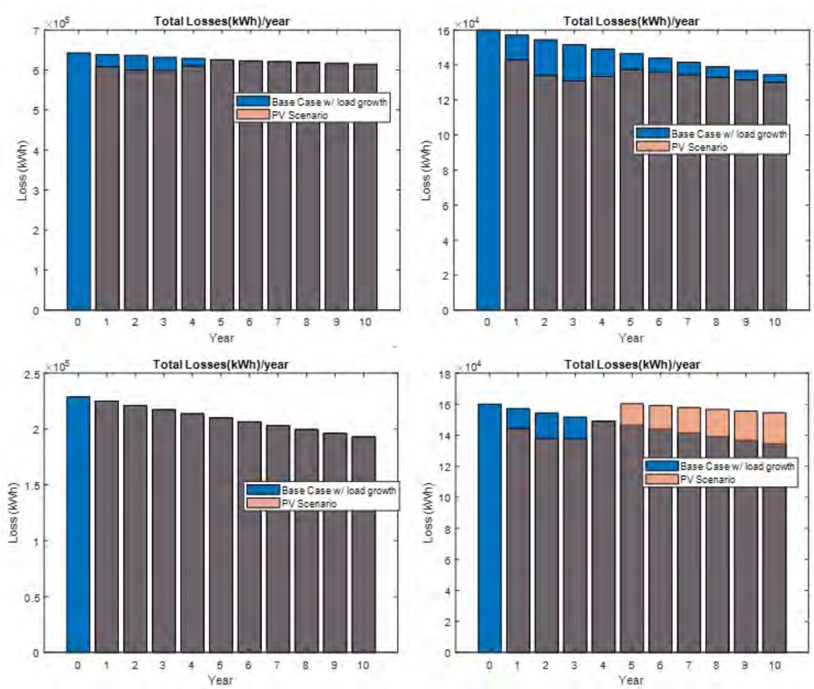

Figure 62: Feeder-wise losses per year - with and without PV, Top Left: J1, Top Right: IEEE 123 PV1, Bottom Left: IEEE 123 No PV, Bottom Right: IEEE 123 PV2

5.1.5 Feeder Upgrades

Feeder Upgrades due to line section and equipment overloads

As in the previous cases (case 1 & 2), PV does not defer upgrades but requires upgrades that would ideally be considered during the interconnection process. Hence this component has not been monetized.

Feeder upgrades due to Voltage Violations

The figure below shows the results for J1, since no issues have been observed on the IEEE 123 Node feeder, those results have been omitted. When we compare the results for J1, the no-PV plots(left) and with-PV plots, do not show any differences. While the maximum circuit voltages do exceed 1.05 Vpu, these are not caused by PV and as such no additional mitigation would be required.

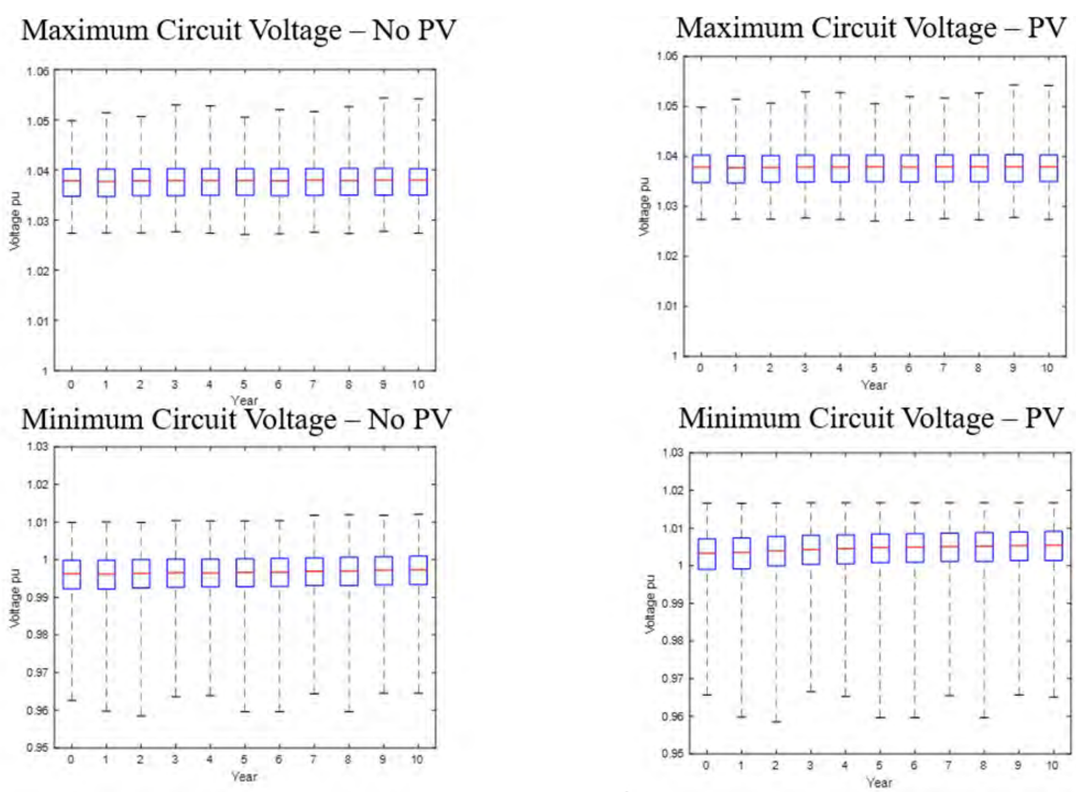

Figure 63: J1 - Voltage Statistics - with and without PV

5.2 Cost Estimate for Service Components

5.2.1 Substation Capacity Deferral

As is the case with case 2, no substation capacity is deferred as the system peak remains almost the same across the planning period.

5.2.2 Substation Equipment Service Life

In contrast to the results in case 2, we see an increase in substation LTC operations and their associated (negative) avoided cost, as seen in the table below. This increase peaks at year 5 followed by some reduction upto year 10.

Table 25: LTC operation and estimated avoided cost

Year	LTC Operation (Base Case)	LTC Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	2,257	2,257	0	0
1	2,289	2,375	-86	-86
2	2,331	2,573	-242	-242
3	2,366	2,700	-334	-334
4	2,434	2,820	-386	-386
5	2,480	2,892	-412	-412
6	2,544	2,896	-352	-352
7	2,532	2,902	-370	-370
8	2,566	2,910	-344	-344
9	2,587	2,939	-352	-352
10	2,611	2,939	-328	-328

5.2.3 Feeder Equipment Service Life

Similar to the results in case 2, we see an increase in LVR operations and their associated (negative) avoided cost as seen in the table below. The maximum increase occurs in year 5 (year with maximum PV), afterwhich the avoided operations reduces towards year 10.

Table 26: Total LVR Operations and estimated avoided cost

Year	Total LVR Operation (Base Case)	Total LVR Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	59,052	59,052	0	0
1	59,527	59,129	398	398
2	59,817	61,745	-1,928	-1928
3	60,508	63,318	-2,810	-2810
4	61,657	66,531	-4,874	-4874
5	63,305	68,503	-5,198	-5198
6	63,829	68,286	-4,457	-4457
7	63,623	68,777	-5,154	-5154
8	64,640	68,910	-4,270	-4270
9	65,292	69,043	-3,751	-3751
10	64,699	69,084	-4,385	-4385

Total capacitor switching operations are shown in the table below. There appears to be an initial increase upto year 5 followed by a gradual decrease upto year 10, similar to what is seen in case 2.

Table 27: Capacitor Operations

Year	Total CAP Operations (Base Case)	Total CAP Operations (with PV)	Avoided Operations
0	3,237	3,237	0
1	3,207	3,175	32
2	3,313	3,477	-164
3	3,412	3,621	-209
4	3,516	3,684	-168
5	3,529	3,795	-266
6	3,635	3,861	-226
7	3,581	3,859	-278
8	3,775	4,003	-228
9	3,757	3,933	-176
10	3,816	3,920	-104

5.2.4 Distribution System Power Loss

The monetized value of distribution system losses are shown in the table below. The maximum reduction in system losses are seen in year 3 followed by a gradual but consistent decrease in avoided losses till year 10. This trend is similar to those seen in case 2.

Table 28: Cost of avoided loss due to PV

Year	Total Loss (MWh) (Base Case)	Total Loss (MWh) (PV)	Avoided Losses (MWh)	Avoided Losses ($)
0	1,850.06	1,850.06	0.00	0
1	1,823.30	1,693.09	130.21	4192.62
2	1,798.05	1,601.54	196.51	6327.47
3	1,772.18	1,552.42	219.76	7076.25
4	1,747.73	1,554.43	193.30	6224.1
5	1,723.63	1,582.67	140.96	4538.87
6	1,700.27	1,566.52	133.75	4306.82
7	1,677.41	1,550.80	126.61	4076.85
8	1,655.26	1,536.22	119.04	3833.13
9	1,634.42	1,521.44	112.98	3637.98
10	1,613.27	1,506.91	106.35	3424.57

5.2.5 Total Cost of Service

The total cost of service for each year of the analysis period obtained using the aforementioned results is shown in the figure below. Unlike the reversal in trend seen in case 2, scenario I, here, the avoided losses do not experience a reversal in trend. Also, unlike case 2, scenario I, there is an increase in LVR operations right from year 2 as opposed to the initial benefit upto year 3 seen in case 2.

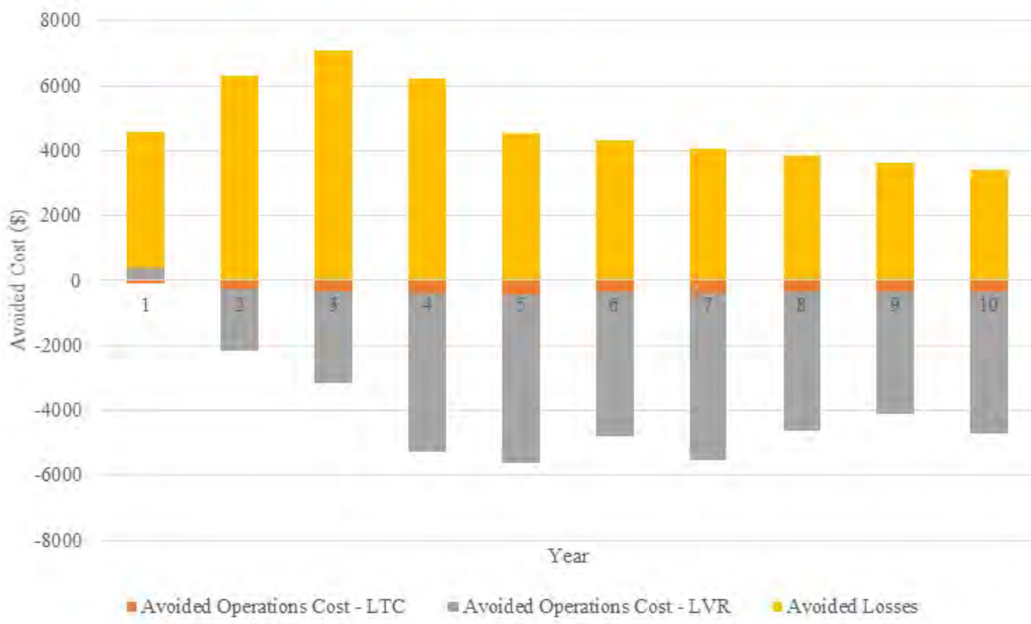

Figure 64: Total Avoided Cost of Service Per-Year: Case 3, Load Growth I

5.3 Observations for Scenario I

The results from this sample case indicate that:

1. PV does not significantly change the maximum demand experienced by the substation
2. PV increases LTC, LVR, and Capacitor operations as its penetration increases
3. Owning to the lower substation loading, this system experiences higher (and always positive) avoided losses
4. No additional voltage issues are observed on this system.

5.4 Load growth scenario II

Peak Load Growth Rate 1%, Energy Growth Rate 0.6%
The same analysis was performed for the load growth case in scenario II. Only the key changes in results are shown below.

5.4.1 Substation Capacity Deferral

Figure 65, shows substation peak demand (kVA) for each year of the analysis. Similar to the results seen in scenario I, there does not appear to be a significant change in substation transformer loading.

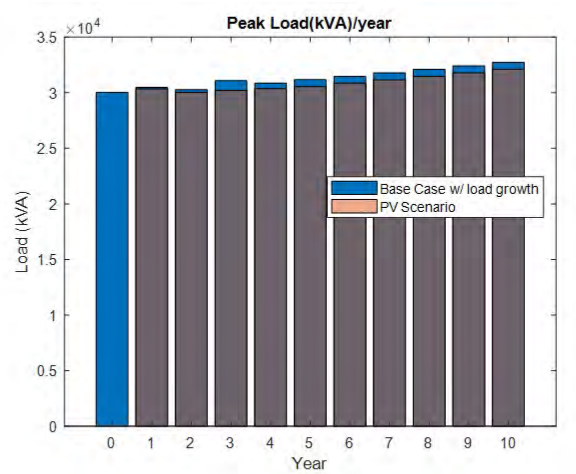

Figure 65: Yearly peak demand at substation - with and without PV

Feeder-wise demand reduction
The figures below show the feederwise peak demand for every year in the simulation period. As opposed to scenario I, we see some reduction in J1, and a lower increase in IEEE 123 PV1 and PV2 due to the offset effect of the higher peak load (and energy) growth rate.

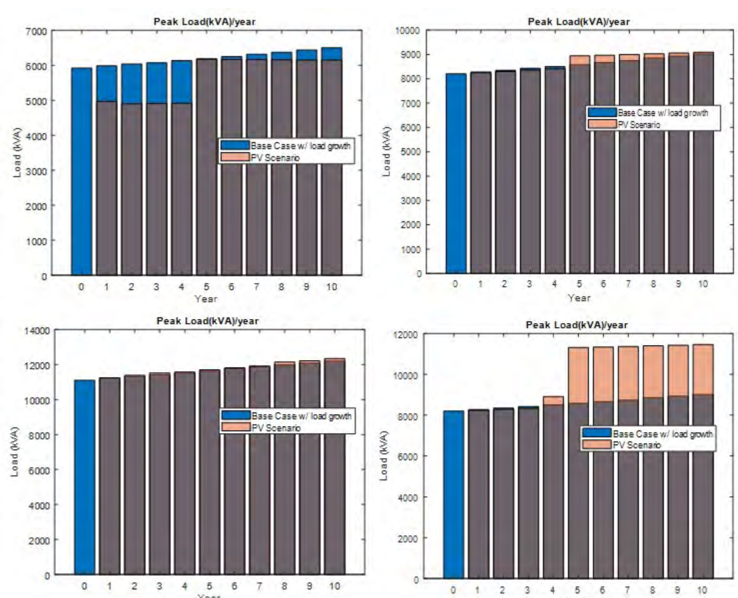

Figure 66: Feeder-wise yearly peak demand - with and without PV, Top Left: J1, Top Right: IEEE 123 PV, Bottom: IEEE 123 No PV

5.4.2 Distribution System Power Loss

The results for the entire distribution system as well as only the substation for every year of the analysis period is shown in the figure below. compared to scenario I, we see a greater reduction in system losses, especially at the substation due to the positive energy growth. The maximum reduction in power loss is seen in year 3 after which the trend reverses, increasing at a constant rate until year 10. As is the previous scenario, the reduction in losses is mainly the result of the reduction in losses at the substation transformer due to lower average loading.

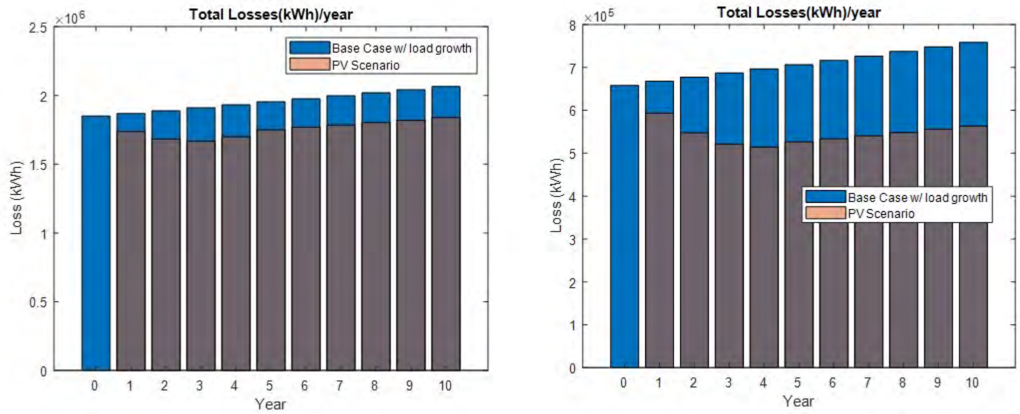

Figure 67: Distribution System Total losses per year - with and without PV, Left: Total Distribution System, Right: Substation area

The results for the feeder wise losses (kWh) are shown in the figure below. Compared to the results in scenario I, we see a greater reduction (or a lesser increase) in power loss over the 10 year period. J1, IEEE 123 PV1 and PV2 experience the most reduction in power loss in year 2/3 after which the trend reverses, even to the point of increasing beyond the base case for IEEE 123 PV2.

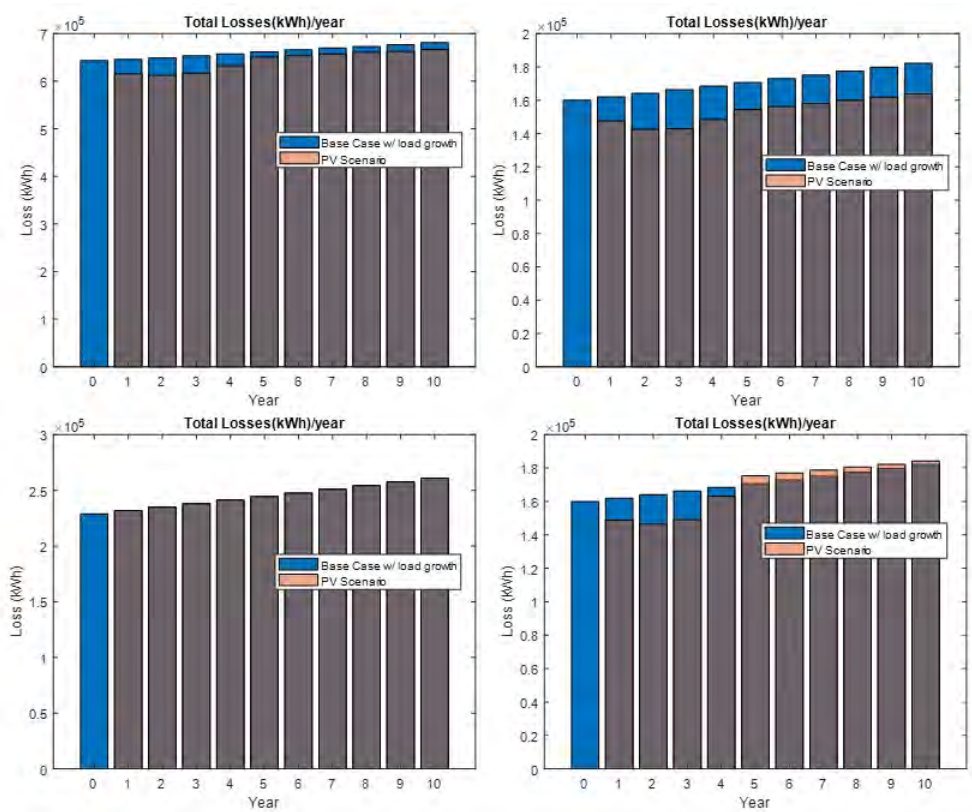

Figure 68: Feeder-wise total losses per year - with and without PV, Top Left: J1, Top Right: IEEE 123 PV1, Bottom Left: IEEE 123 No PV, Bottom Right: IEEE 123 PV2

5.4.3 Feeder Upgrades

Feeder Upgrades due to voltage violations
As in the previous case, no change in voltage violations were observed between the base case and the case with PV.

5.5 Cost Estimate for Service Components

5.5.1 Substation Equipment Service Life

The results for the avoided cost due to LTC operations are shown in the table below. The cost increases steadily uptil year 6 after which it stagnates. This is in contrast decrease seen in scenario I.

Table 29: LTC operation and estimated avoided cost

Year	LTC Operation (Base Case)	LTC Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	2,257	2,257	0	0
1	2,313	2,395	-82	-82
2	2,313	2,523	-210	-210
3	2,313	2,667	-354	-354
4	2,351	2,797	-446	-446
5	2,401	2,891	-490	-490
6	2,411	2,931	-520	-520
7	2,455	2,945	-490	-490
8	2,480	2,970	-490	-490
9	2,516	3,004	-488	-488
10	2,536	3,048	-512	-512

5.5.2 Feeder Equipment Service Life

Similar to the earlier scenario, we see an increase in total LVR operations cost up to year 5 followed by a gradual decrease in the result shown in the table below. The avoided costs although negative are higher than those in scenario I due to the higher peak demand growth rate.

Table 30: Total LVR operations and estimated avoided cost

Year	Total LVR Operation (Base Case)	Total LVR Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	59,052	59,052	0	0
1	60,396	60,849	-453	-453
2	61,876	62,719	-843	-843
3	62,956	64,609	-1,653	-1653
4	63,375	67,364	-3,989	-3989
5	64,774	70,345	-5,571	-5571
6	66,419	71,085	-4,666	-4666
7	67,711	72,484	-4,773	-4773
8	70,002	73,636	-3,634	-3634
9	71,134	75,389	-4,255	-4255
10	73,603	77,228	-3,625	-3625

Total capacitor switching operations are shown in the table below. While the results are not monetized as before, there does not appear to be a consistent trend in their operation.

Table 31: Capacitor Operations

Year	Total CAP Operations (Base Case)	Total CAP Operations (with PV)	Avoided Operations
0	3,237	3,237	0
1	3,095	3,276	-181
2	3,271	3,360	-89
3	3,265	3,510	-245
4	3,223	3,624	-401
5	3,397	3,726	-329
6	3,419	3,752	-333
7	3,498	3,698	-200
8	3,629	3,849	-220
9	3,644	3,749	-105
10	3,640	3,845	-205

5.5.3 Distribution System Power Loss

The results of distribution system power loss are shown in the table below. Compared with the results in scenario I, the results in this case are significantly higher, almost two times the values in scenario I.

Table 32: Cost of avoided loss due to PV

Year	Total Loss (MWh) (Base Case)	Total Loss (MWh) (PV)	Avoided Losses (MWh)	Avoided Losses ($)
0	1,850.06	1,850.06	0.00	0
1	1,869.49	1,737.12	132.37	4262.33
2	1,889.54	1,683.49	206.06	6635
3	1,910.98	1,667.96	243.02	7825.22
4	1,932.05	1,699.22	232.83	7497.17
5	1,953.77	1,750.72	203.06	6538.4
6	1,975.59	1,767.64	207.95	6695.91
7	1,997.36	1,785.57	211.79	6819.76
8	2,019.54	1,802.82	216.73	6978.56
9	2,042.00	1,820.18	221.81	7142.39
10	2,064.78	1,839.11	225.66	7266.41

5.5.4 Total Cost of Service

Using the results presented above, the total cost of service is computed and shown in the figure below. As pointed out earlier, distribution system power loss is higher (more benefit). While the avoided LVR operations are lower (more cost) than scenario I.

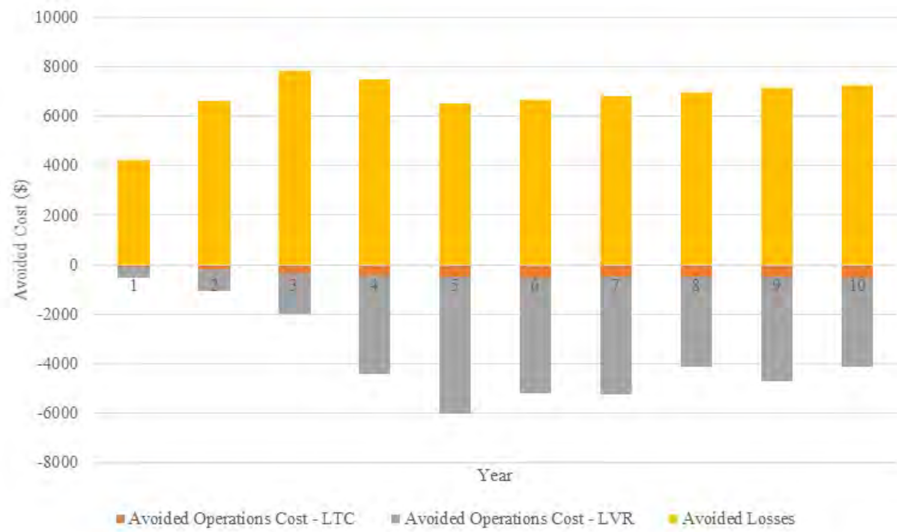

Figure 69: Total Avoided Cost of Service Per-Year: Case 3, Load Growth II

5.6 Observations on Scenario II

The results from this scenario II indicate that:

1. PV does not significantly change the maximum demand experienced by the substation, similar to scenario I
2. PV increases LTC, LVR, and Capacitor operations as its penetration increases, more than scenario I
3. The results for avoided distribution power loss show a higher value when compared to scenario I
4. No additional voltage issues are observed on this feeder, similar to scenario I.

6 Simulation Results - Case 4

As indicated before, this case corresponds to a an actual large scale distribution system. Simulations have been performed for this case as well under the two different load growth scenarios.

6.1 Load growth scenario I

Peak Load Growth rate 0.21%, Energy Growth -1.02%

The results obtained from simulations are summarized below. The summary compares the change in each metric considered as PV penetration increases over the planning period.

6.1.1 Substation Capacity Deferral

The figure below shows the year-wise peak demand (kVA) at the substation for the case with and without PV. Similar to Case 2 and 3, we do not see any significant reduction (or increase) in substation peak demand. The minor reduction gradually increases till year 5 after which there is a reversal in trend until year 10.

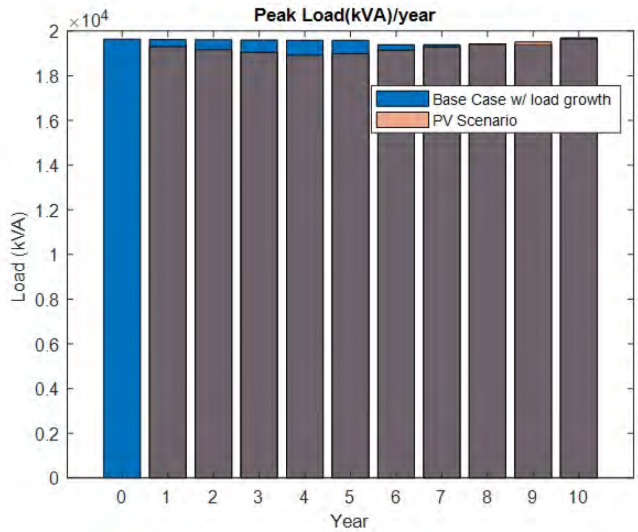

Figure 70: Yearly peak demand at substation - with and without PV

Feeder-wise demand reduction THe feeder-wise disaggregated results of figure 70 are shown below. B01 has a reduction in peak demand in year 1 and 2 followed by a reversal in trend that continues till year 5, afterwhich it saturates. B03 does not experience such a reduction in year 1 and 2, however, there is a steady increase from year 3 to year 5. As explained earlier since these demands are noncoincident, they do not add up to increases the overall peak demand on the substation.

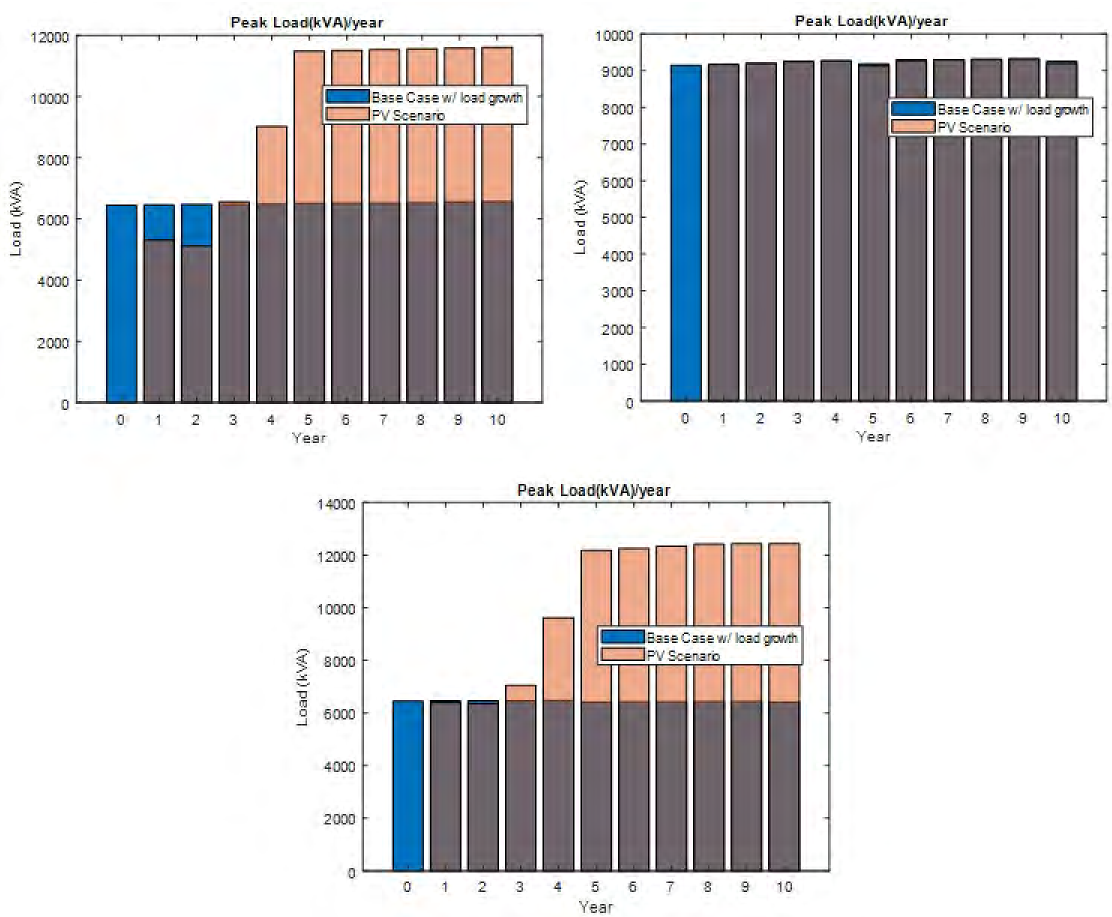

Figure 71: Feeder-wise yearly peak demand - with and without PV, Top Left: B01, Top Right: B02, Bottom: B03

When we look at the real power flow (kW) across the final year of our planning period (year 10) for the case with and without PV, we see that due to the winter peaking nature of the overall load profile, the addition of PV does not result in an increase in peak demand. Similar to earlier cases, the the maximum reverse power flow is seen during spring and fall, the maximum reverse real power flow in spring is almost equal to the maximum forward real power flow in winter.

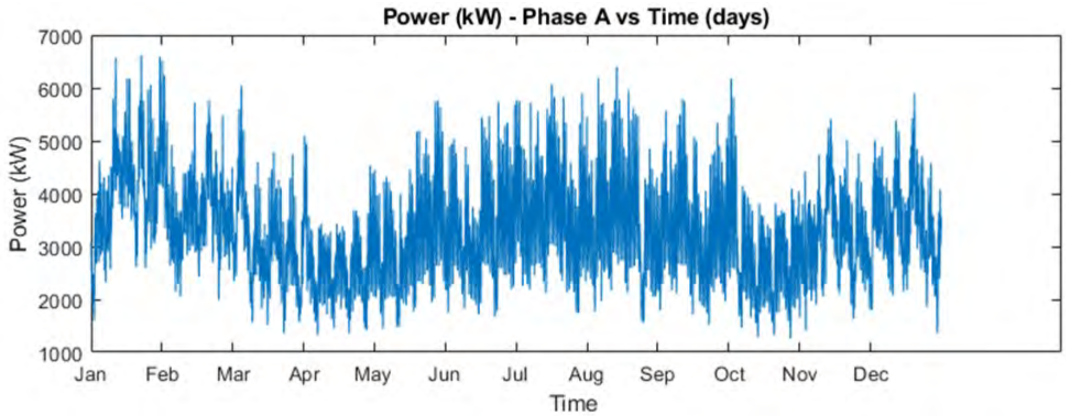

Figure 72: Net load at substation during year 10 without PV

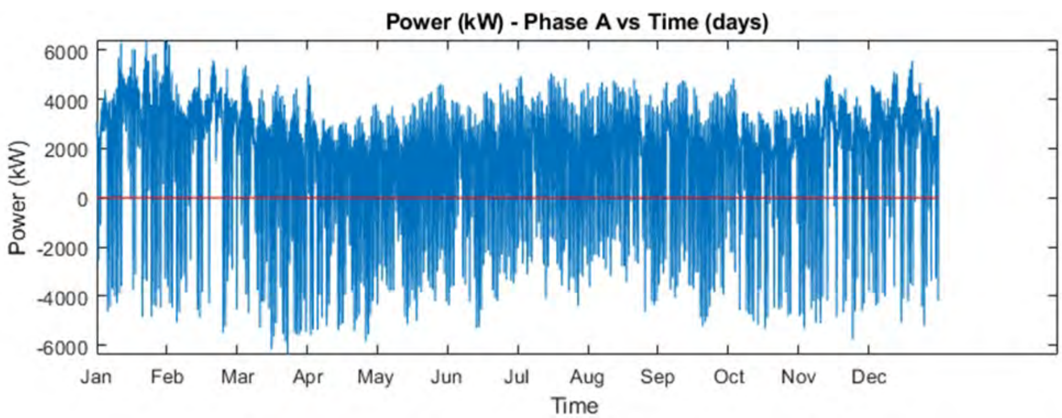

Figure 73: Net load at substation during year 10 with PV

Looking at the total demand at the substation for the entire year, in year 10 of the analysis period with and without PV in the figures below, we see that the peak demand (kVA) has shifted from early February to late March, although the value has not changed significantly. We can also see that the average loading on the substation transformer has reduced from 12MVA to 0.75MVA. This will help lower substation losses as we will subsequently see.

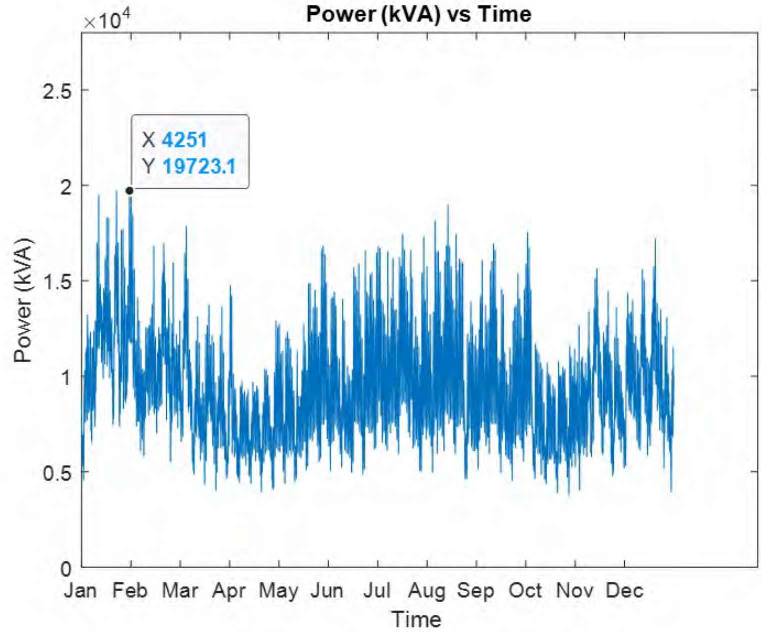

Figure 74: Net load profile year 10 - base case (No PV)

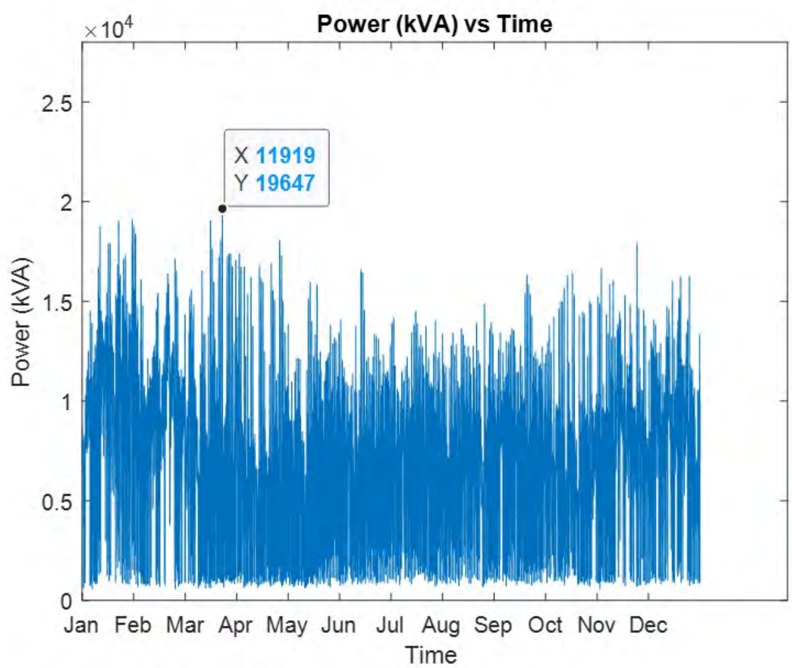

Figure 75: Net load profile year 10 - with PV

6.1.2 Substation Equipment Service

OLTC Operation:
The year-wise OLTC results are shown in the figure below. We see that there is a general reduction in OLTC operations in the case with PV.

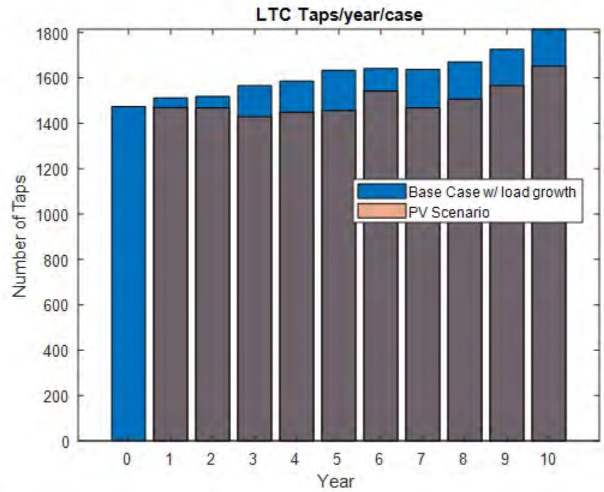

Figure 76: OLTC operations per year with and without PV

Transformer Loading: Looking at the results in case 1, 2, and 3, we see that transformer loss of life is purely a function of transformer average loading, which serves as a good proxy. Also, since in all the cases analysed, the transformer is not heavily loaded (on average) in the base case, the benefit in loss of life reduction due to PV is not significant. Hence, the loss of life analysis was not repeated for this feeder configuration.

6.1.3 Feeder Equipment Service Life

The results for LVR operation for BO2 and BO3 are shown in figures 77 and 78, respectively. BO1 does not contain any LVRs. In contrast to the IEEE 123 bus feeder whose LVRs seem to be affected by PVs in adjoining feeders, the LVR operations in BO2 do not change. When we look at the LVR operations in BO3, expectedly, there is a noticeable increase in operations, in some cases as early as year 3, that gradually, albeit inconsistently increases across the study period.

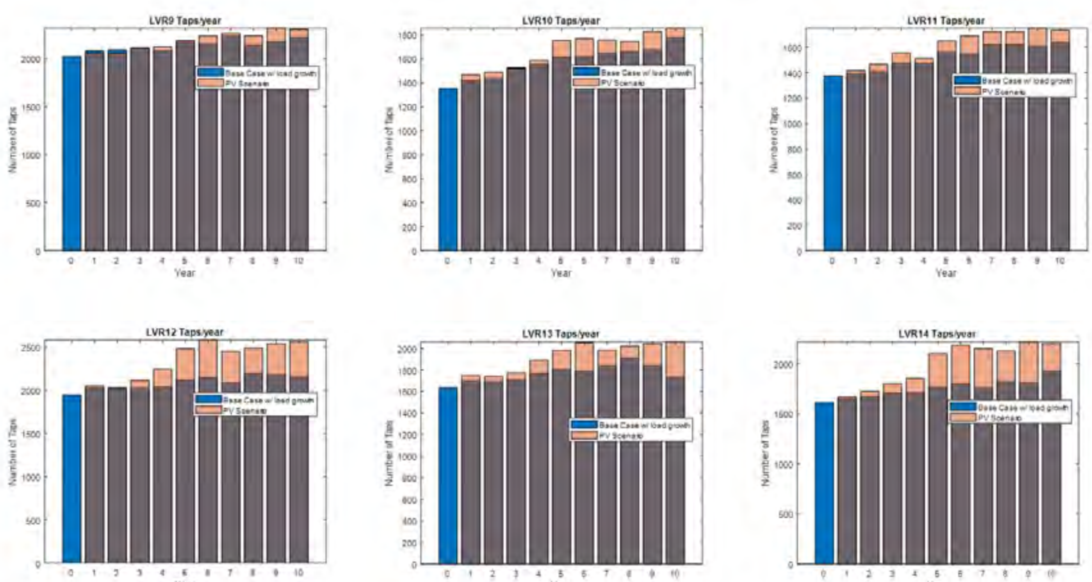

Figure 77: B03 - LVR operations per year with and without PV

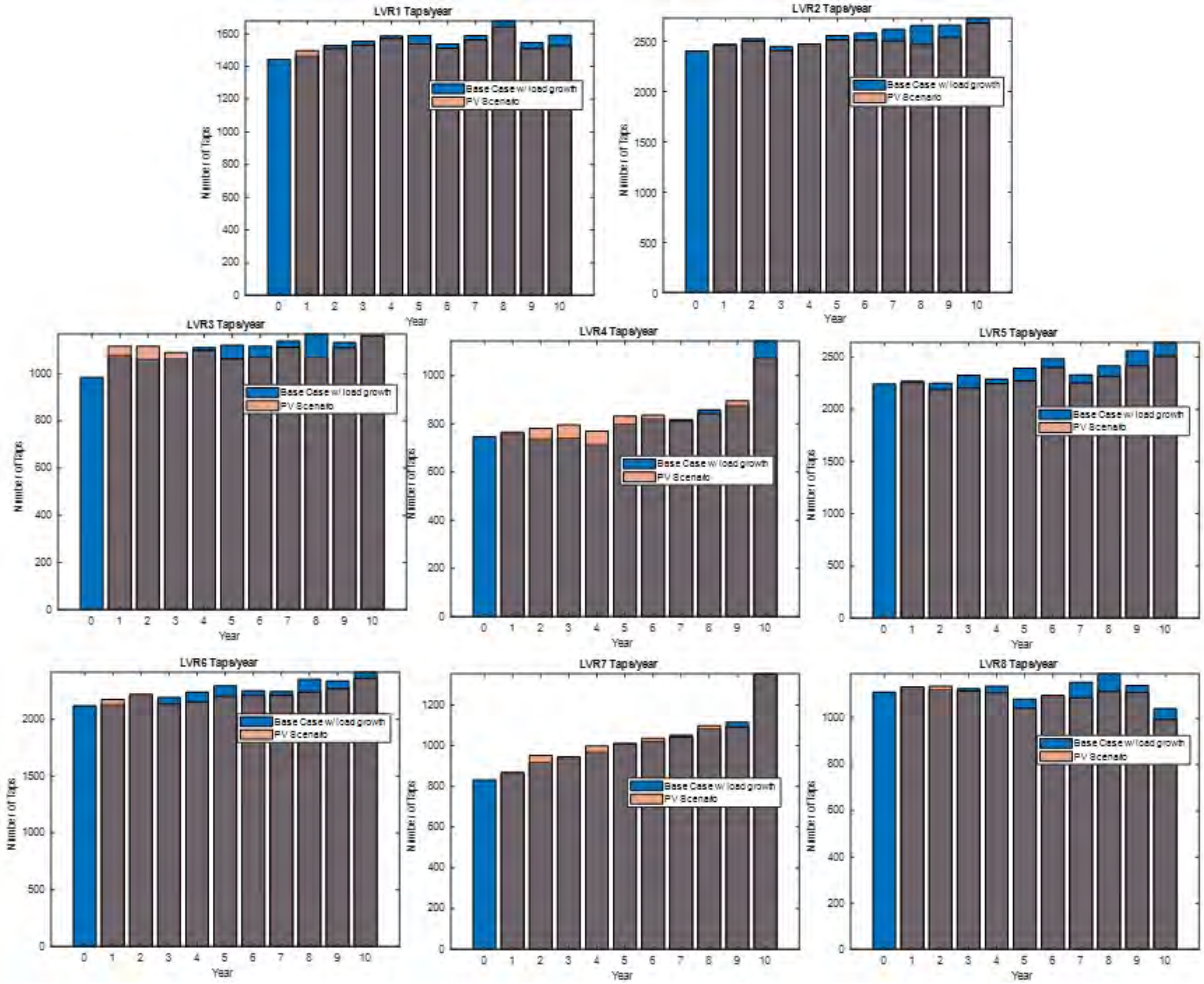

Figure 78: B02 - LVR operations per year with and without PV

Capacitor operations have not been shown as there was no change in their operation with or without PV. The reason being in the earlier feeder, the capacitor control was voltage based. However, as instructed by Duke's field engineers, the capacitors in Duke's feeders were operated in VAR mode with voltage supervision. In the absence of any voltage issues, these capacitors will operate due to the change in VAR demand (from the load), and since the PVs considered for this study operate at unity power-factor, they do not affect the operation of any capacitor bank.

6.1.4 Distribution System Power Loss

The year-wise total distribution system power loss is shown in the figure below. We see a general reduction in total losses. This trend is lowest in year 3, which reverses until year 5 and remains constant thereafter.

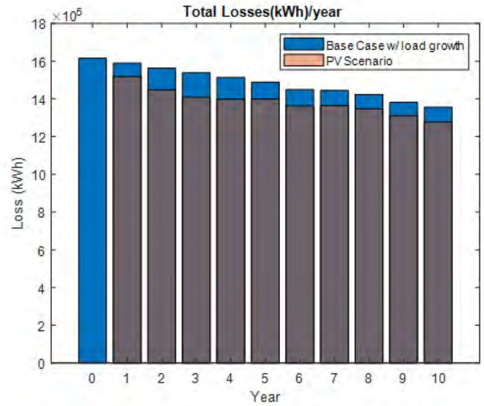

Figure 79: Total distribution system losses per year - with and without PV

The figure below shows the year-wise disaggregated power loss for each feeder and the substation area. Similar to case 2 and 3, we see that reduction in average loading at the substation has resulted the reduction of power loss at the substation, which is the largest component. B01 experiences an increase in losses from year 4; this increase remains constant until year 10. BO2, expectedly is not affected by the presence of PVs in BO1 & BO3. BO3 sees a minuscule reduction in power loss.

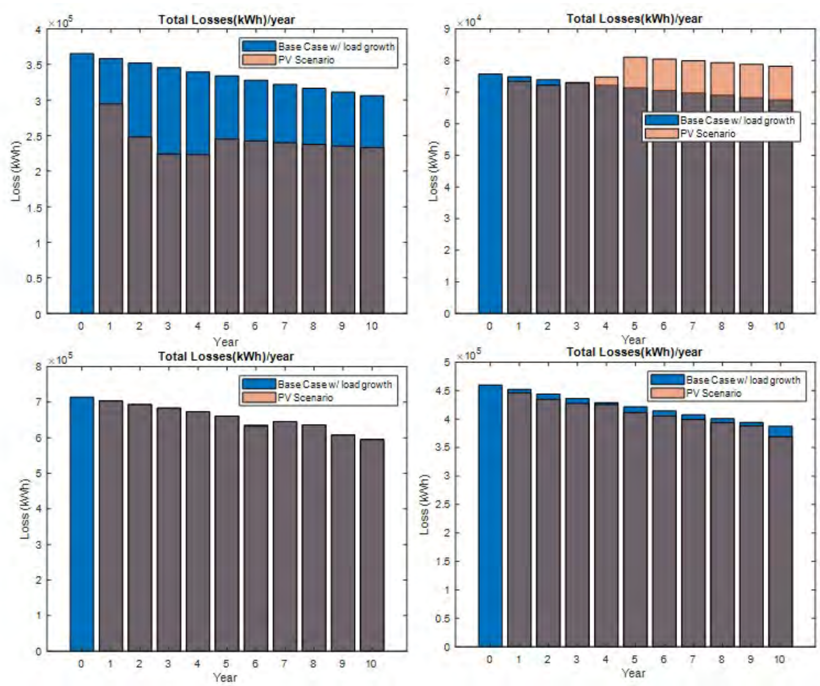

Figure 80: Feeder-wise losses per year - with and without PV, Top Left: Substation Area, Top Right: B01, Bottom Left: B02, Bottom Right: B03

6.1.5 Feeder Upgrades

Feeder upgrades due to line section and equipment overloads
No overloads were observed in any line section or primary feeder equipment during the course of this simulation.

Feeder Upgrades due to Voltage Violations
The year-wise voltage statistics for B01, B03 are shown below. The results for BO2 are not shown because no PV has been added to this feeder and the LVR result do not change between the base case and PV case, implying no change in voltages. Looking at the voltage statistics of B01 and B03, we see that the presence of PV has not caused any voltage violations on either feeder.

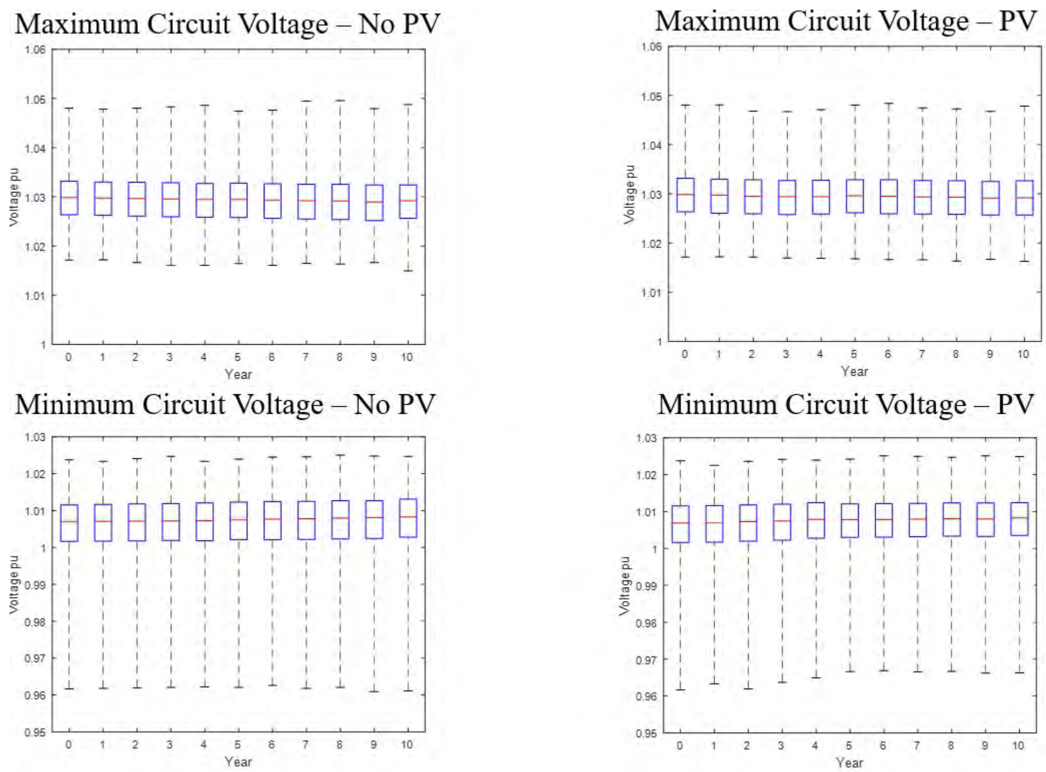

Figure 81: B01 - Voltage Statistics - with and without PV

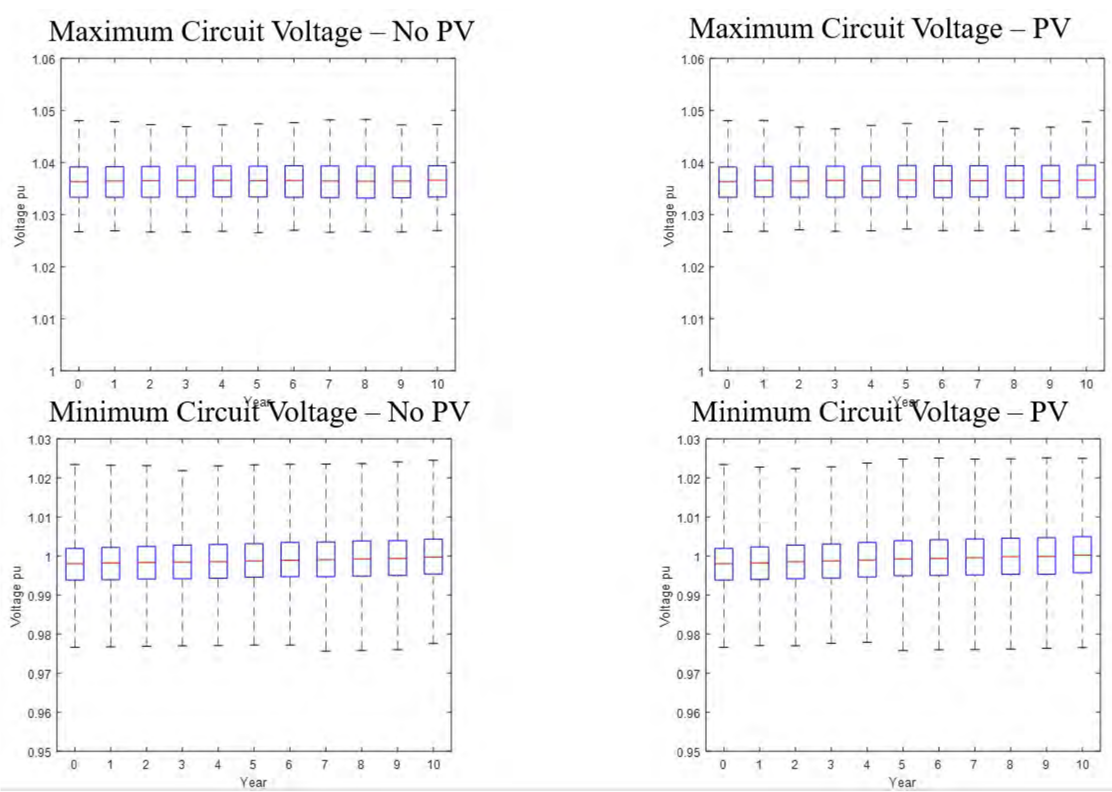

Figure 82: B03 - Voltage Statistics - with and without PV

6.2 Cost Estimate for Service Components

6.2.1 Substation Capacity Deferral

As there was no change in substation peak demand (kVA) during the course of this simulation, this component is not considered.

6.2.2 Substation Equipment Service Life

The monetized value of avoided LTC operations is shown in the table below. Unlike other feeder configurations evaluated, we do not see any increase in LTC operations, rather we see a decrease in operations which increases in magnitude until year 5 and remains more or less constant thereafter.

Table 33: LTC operation and estimated avoided cost

Year	LTC Operation (Base Case)	LTC Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	1,474	1,474	0	0
1	1,512	1,470	42	42
2	1,518	1,468	50	50
3	1,566	1,428	138	138
4	1,586	1,448	138	138
5	1,634	1,456	178	178
6	1,642	1,542	100	100
7	1,638	1,468	170	170
8	1,670	1,506	164	164
9	1,726	1,566	160	160
10	1,814	1,652	162	162

6.2.3 Feeder Equipment Service Life

The monetized value of avoided LVR operations is presented in the table below. Following the trend of seen in the earlier results, there is an increase in LVR operations in the PV case that peaks in year 6 and reduces thereafter. Since the value of avoided cost is always negative, this component is always a cost during the simulation period.

Table 34: Total LVR operations and estimated avoided cost

Year	Total LVR Operation (Base Case)	Total LVR Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	21,839	21,839	0	0
1	22,447	22,697	-250	-250
2	22,691	22,903	-212	-212
3	22,942	23,108	-166	-166
4	23,158	23,632	-474	-474
5	23,898	24,644	-746	-746
6	23,973	25,191	-1,218	-1218
7	24,141	24,927	-786	-786
8	24,766	25,137	-371	-371
9	24,665	25,647	-982	-982
10	25,547	26,390	-843	-843

6.2.4 Distribution System Power Loss

Similar to case 2 and 3, there is a general reduction in distribution system power loss across the simulation period as seen by the results shown in the table below. We that maximum reduction in year 5 followed by a decrease.

Table 35: Cost of avoided loss due to PV

Year	Total Loss (MWh) (Base Case)	Total Loss (MWh) (PV)	Avoided Losses (MWh)	Avoided Losses ($)
0	1,615.02	1,615.02	0.00	0
1	1,588.74	1,518.20	70.55	2271.6
2	1,563.08	1,447.72	115.37	3714.78
3	1,538.01	1,407.59	130.42	4199.6
4	1,513.71	1,397.11	116.60	3754.5
5	1,487.93	1,398.78	89.15	2870.76
6	1,448.18	1,360.41	87.77	2826.19
7	1,444.38	1,364.40	79.98	2575.31
8	1,422.39	1,346.85	75.54	2432.45
9	1,381.03	1,309.86	71.17	2291.54
10	1,355.12	1,275.91	79.22	2550.76

6.2.5 Total Cost of Service

Summarizing the results presented in the tables above, the below bar plot is created to show the year-wise trend in the cost of service components. Avoided power loss is a benefit while increased LVR operations results in some costs of lower magnitude.

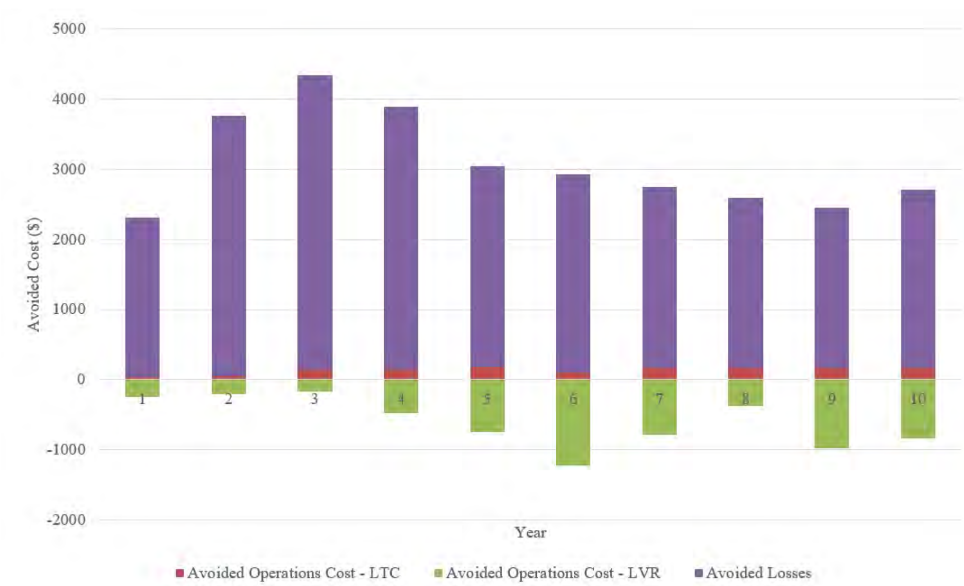

Figure 83: Total Avoided Cost of Service Per-Year: Case 4, Load Growth I

6.3 Observations for Scenario I

The results from this sample case indicate that:

1. PV does not significantly change the maximum demand experienced by the substation
2. PV increases LVR operations that peak in year 5 but decreases LTC operations over the simulation period.
3. Since the capacitor banks were configured in VAR mode, no change in operation was observed between the cases with and without PV
4. Owning to the lower substation loading, this system experiences higher (and always positive) avoided losses
5. No additional voltage issues are observed on this system.

6.4 Load growth scenario II

Peak Load Growth Rate 1%, Energy Growth Rate 0.6%

The same analysis was performed for the load growth case in scenario II. Only the key changes in results are shown below.

6.4.1 Substation Capacity Deferral

As in scenario I, the presence of PV does not affect the peak demand (kVA) at the substation as seen in the figure below. While a minor decrease is observed, it is not significant enough to warrant any capacity deferral.

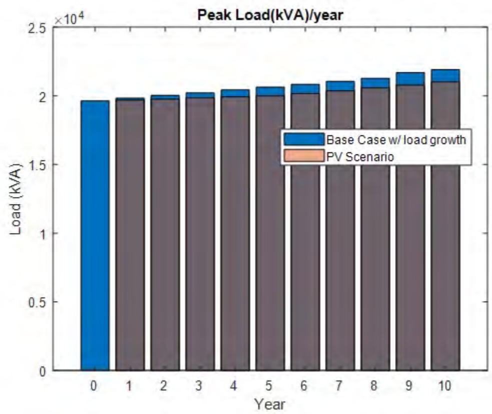

Figure 84: Yearly peak demand at substation - with and without PV

Feeder-wise demand reduction
Looking at the year-wise results of peak demand (kVA), disaggregated by feeder, we see that B01 experiences an increase in peak demand due to reverse power flow which peaks in year 5, after the initial reduction in year 1 and 2 and reversal thereafter. No change was expected or seen in the peak demand of B02.

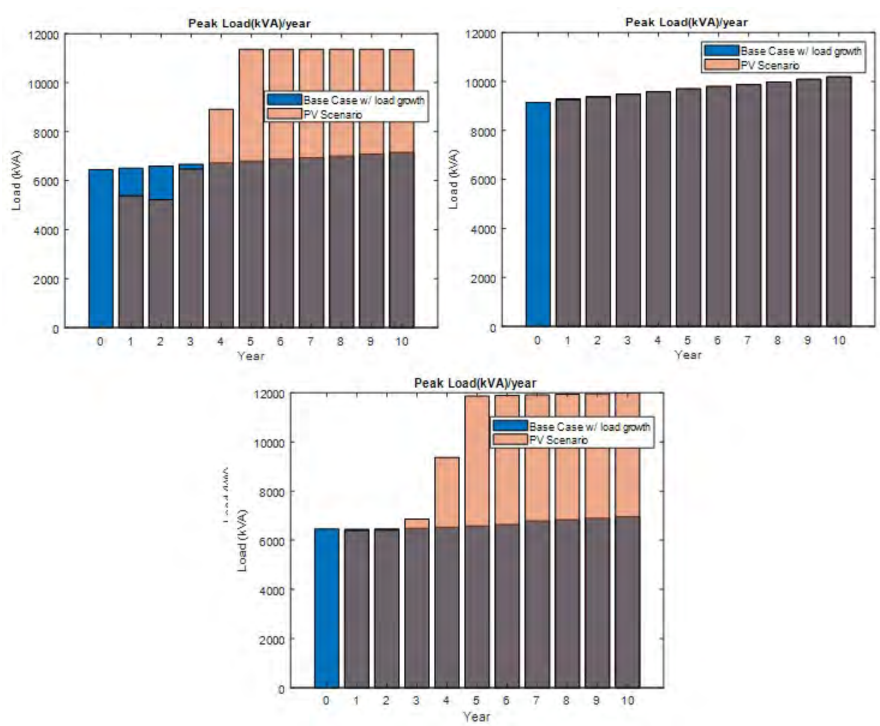

Figure 85: Feeder-wise yearly peak demand - with and without PV, Top Left: B01, Top Right: B02, Bottom: B03

The results for B03 are similar to those seen in scenario I, i.e. a sharp increase in peak demand that stagnates from year 5. However, unlike B01 in this case, there is no initial decrease in feeder peak demand.

6.4.2 Distribution System Power Loss

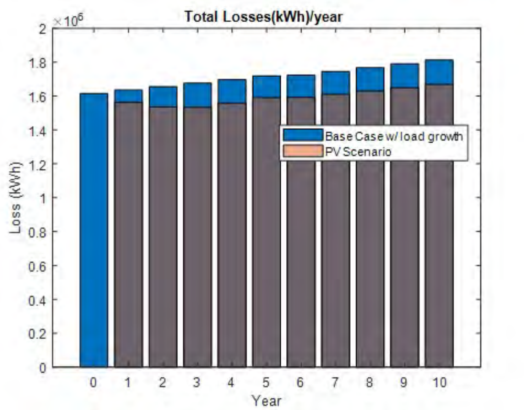

Figure 86: Total losses per year - with and without PV

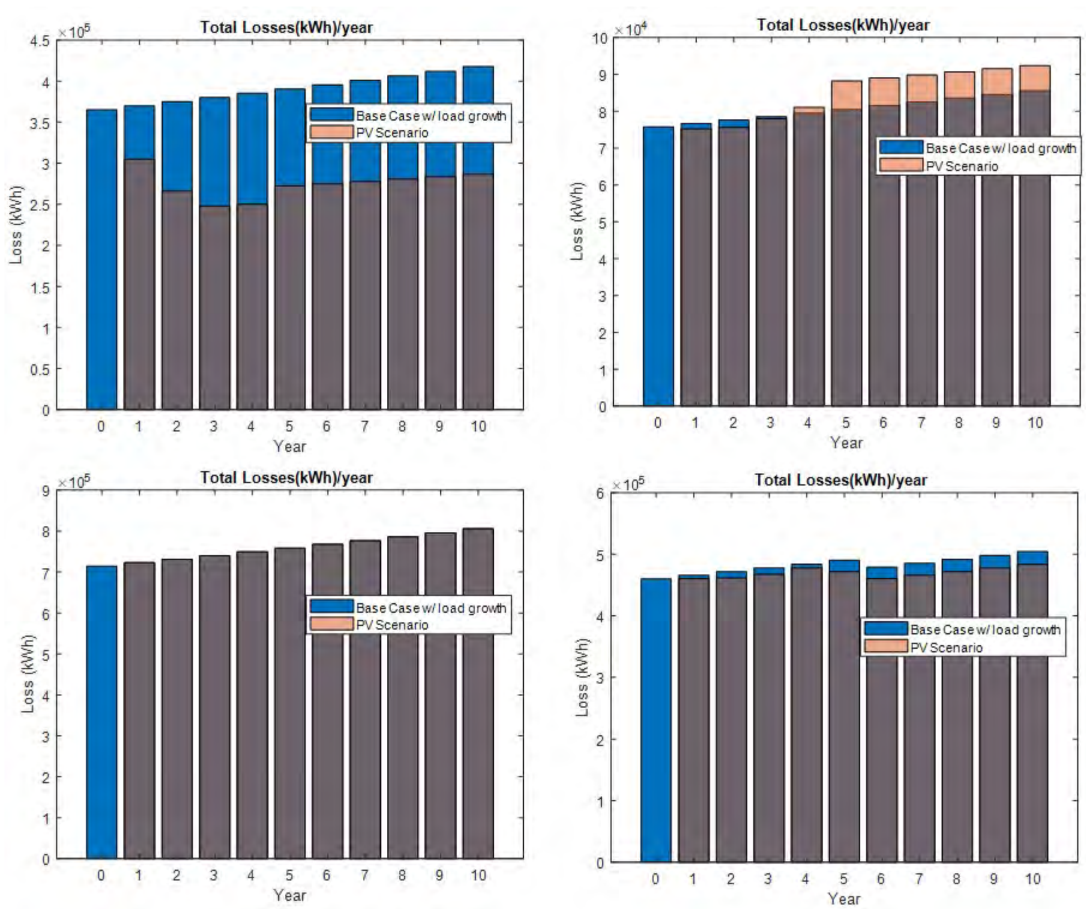

Figure 87: Feeder-wise total losses per year - with and without PV, Top Left: Substation, Top Right: B01, Bottom Left: B02, Bottom Right: B03

6.4.3 Feeder Upgrades

Upgrades due to line section and equipment overloads
No overload were detected in line section or primary feeder equipment.

Upgrades due to Voltage Violations
As in the previous case, no change in voltage violations were observed.

6.5 Cost Estimate for Service Components

6.5.1 Substation Equipment Service Life

The table below shows the monetized values of avoided operations cost for the LTC in this feeder configuration. The avoided operations cost increases steadily until year 10.

Table 36: LTC operation and estimated avoided cost

Year	LTC Operation (Base Case)	LTC Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	1,474	1,474	0	0
1	1,484	1,476	8	8
2	1,516	1,490	26	26
3	1,586	1,524	62	62
4	1,586	1,496	90	90
5	1,628	1,482	146	146
6	1,690	1,530	160	160
7	1,734	1,550	184	184
8	1,788	1,604	184	184
9	1,836	1,654	182	182
10	1,878	1,684	194	194

6.5.2 Feeder Equipment Service Life

Similar to the results seen in scenario I, we see an increase in LVR operations when compared to the base case shown in the table below. This results in a negative avoided operations cost (implying a cost). This cost appears to monotonically increase, marginally peaking in year 7 but remaining fairly consistent otherwise.

Table 37: Total LVR operations and estimated avoided cost

Year	Total LVR Operation (Base Case)	Total LVR Operation (with PV)	Avoided Operations	Avoided Operations Cost ($)
0	21,839	21,839	0	0
1	22,019	22,417	-398	-398
2	22,487	23,046	-559	-559
3	23,155	23,511	-356	-356
4	23,489	24,095	-606	-606
5	23,747	24,758	-1,011	-1011
6	23,963	25,073	-1,110	-1110
7	24,270	25,589	-1,319	-1319
8	24,565	25,735	-1,170	-1170
9	25,249	26,433	-1,184	-1184
10	25,669	26,793	-1,124	-1124

6.5.3 Distribution System Power Loss

The avoided distribution system power loss components for this feeder configuration is positive throughout the simulation period as seen in the table below; this is similar to the trend in scenario I. However, unlike scenario I, we see a double peak in year 3 and year 10. The higher peak demand (and energy) growth rate in comparison to the value in scenario I.

Table 38: Cost of avoided loss due to PV

Year	Total Loss (MWh) (Base Case)	Total Loss (MWh) (PV)	Avoided Losses (MWh)	Avoided Losses ($)
0	1,615.02	1,615.02	0.00	0
1	1,635.26	1,563.28	71.98	2317.76
2	1,655.70	1,534.59	121.11	3899.8
3	1,676.49	1,533.06	143.43	4618.48
4	1,697.66	1,557.74	139.92	4505.31
5	1,719.13	1,590.55	128.57	4140.01
6	1,723.40	1,591.69	131.71	4241.06
7	1,745.36	1,610.29	135.07	4349.1
8	1,767.62	1,629.22	138.40	4456.51
9	1,790.25	1,648.44	141.81	4566.36
10	1,813.24	1,668.05	145.19	4675.03

6.5.4 Total Cost of Service

The data presented in the tables above is used to prepare the figure shown below that illustrates the trends in each cost of service component.

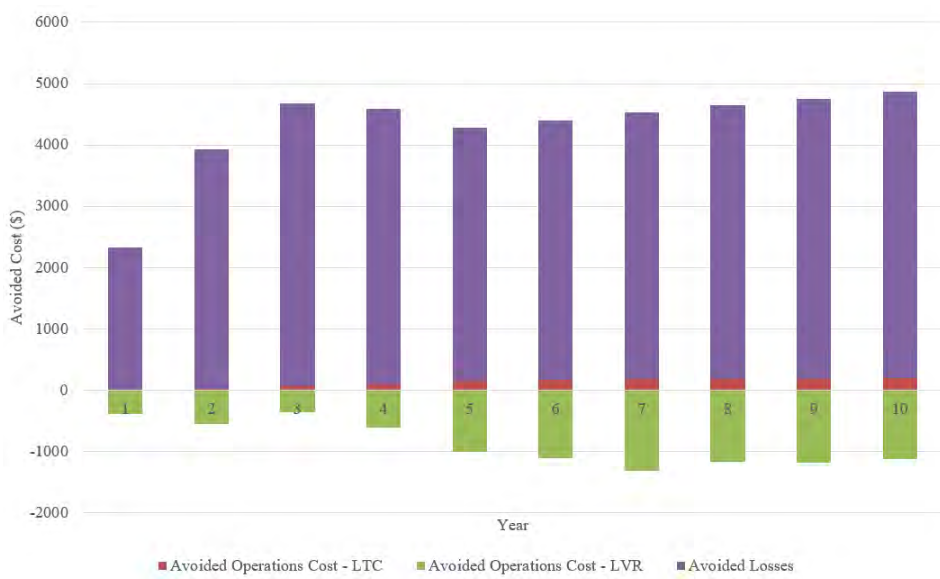

Figure 88: Total Avoided Cost of Service Per-Year: Case 4, Load Growth II

6.6 Observations on Scenario II

The results from this scenario II indicate that:

1. PV does not significantly change the maximum demand experienced by the substation, similar to scenario I
2. The LTC, LVR, and Capacitor behavior is similar to that seen in scenario I
3. The results for avoided distribution power loss show a higher value when compared to scenario I due to the higher peak demand and energy growth rates in comparison to scenario I
4. No additional voltage issues are observed on this feeder, similar to scenario I.

7 Cumulative Observations

These case studies focused on the cost-benefits of integrating large scale solar farms (utility scale PV) on four sample distribution systems. The case studies considered the main benefit and cost components identified and used a multi-year time period with increasing PV penetration on the distribution feeders in order to obtain an estimate for these components. The study considers also two different load growth scenarios. Time-series analysis based simulations with one-minute resolution have been carried out to obtain these estimates (see next section 8 for more details). The results based on these cases indicate that:

1. PV provides capacity relief at the substation (reduction of loading on the substation transformer) up to high levels of installed PV capacity. The relief is small, approximately 10% of installed PV capacity up to 90-130% PV penetration. This capacity relief does not yield capacity deferral on the systems studied, due mainly to the fact that there was enough capacity on the substation transformer to accommodate the slow load growth rate (and thus, there were no capacity upgrades needed for the PV to defer).

2. Substation transformer lifetime extension is another potential benefit PV provides. This is due to capacity relief. The benefit is estimated to be quite low for a typical case of a transformer with moderate loading (70-80% of its capacity).

3. High levels of PV (100% penetration or higher) cause reverse power flow at the substation, and reverse power flow increases with higher penetration levels.

4. Utility scale PV reduces substation LTC operation up to moderate levels (40-60%). Higher levels of PV can cause an increase in LTC operation and the severity depends on the system. For the two large scale systems simulated, while the LTC operation starts increasing at about 40% in case 2, no increase has been observed in case 4.

5. Utility Scale PV has also a similar effect on feeder LVR operation on distribution feeders – marginal reduction in operation up to moderate levels and then increased operation at higher levels. The inflection point from reduced operation to the higher operation is about 40-60% under both load growth scenarios.

6. Utility scale PV can reduce line loading on the feeder up to high level of PV penetration (up to 90%). Higher PV penetration (90% or higher) can increase line overloading, and thus may require additional line upgrades. These upgrades are usually identified and implemented as new utility scale PV farms being integrated to the system, and the upgrade cost is paid the PV owner.

7. Utility Scale PV reduces the power losses on the feeder up to high levels of PV (90-120%). Higher levels can cause an increase in system losses, but the increase is quite small on the large systems studied, case 2, 3, and 4.

8. Utility Scale PV does not cause any significant voltage violations on the systems studied. This is mainly due to the fact that, in these systems, PV systems are connected closer to the substation in the first zone of voltage regulation.

9. The different load growth patterns considered for the case studies impact both the cost and the benefit components only marginally.

10. The cost and benefit components have been monetized using basic cost estimates. The highest cost component is the feeder line upgrade. The benefits/costs associated with LTC and LVR operation are relatively low ($500 to -2000 per year - with positive indicating benefit, and negative indicating cost). Power loss benefit per feeder is also relatively low ($500 to -2000 per year). The results show that the total monetized net benefit (avoided cost) is case specific and can vary considerably. For the four cases studied, for example, while in case 1 the net benefits decreases considerably as PV penetration increases, in case 4, net benefits remains steady even at high PV levels.

8 Computational and Engineering Effort for the Case Study

In order to accurately simulate a distribution system's operation, it is necessary to have detailed and accurate model for the distribution system. This takes considerable amount of engineering effort. In this study, models have been obtained from public domain and also from the local utility. For conducting the simulations for a distribution system, keeping the simulation time resolution as low as practically possible is needed in order to obtain accurate estimates. In this study, a time resolution of 1 minute is deemed as the ideal choice as it helps to monitor the LTC and LVR operation accurately and capture PV variation. However, it must be noted that simulating large distribution systems with several hundred to a few thousand nodes at this resolution will take an inordinate amount of time to complete.

Repeating these simulations for the entire planning horizon (base and PV case) – with load and PV growth considered – would further increase the computation time. Apart from the computation time, the amount of data captured in the results scales inversely with simulation step-size. Thus, it is not possible to simulate large feeders with a solution step-size of 1 min, and hence 10 minute resolution is adopted for large systems and the comparisons were made to make sure that the results are accurate with this increased time resolution. Table 39 below summarises the computational effort for the case studies conducted.

Table 39: Simulation Statistics

	Case 1	**Case 2**	**Case 3**	**Case 4**
Number of Nodes	140	1580	1860	6280
Step-size (min)	1	10	10	10
Number of Cases	42			
Total Runtime (hrs)	8	36	40	52.5
Total Simulation Data Generated (GB)	67	151	160	300

These results indicate that conducting sensitivity analysis becomes even more challenging for large systems as any change in the system would necessitate re-running all the 42 cases. Hence, for large systems, such as case 2, 3, and 4,sensitivity analyses would be prohibitive in terms of both the simulation time and the data storage.

Appendix I

Assessing the Impact of High Penetration PV on the Power Transformer Loss of Life on a Distribution System

Considering the fact that the transformer's lifetime mainly depends on the insulation lifetime, we use these two terms interchangeably in this report. We adopted the models developed in [2, 3, 4, 5] to estimate the transformer loss of life. The heat in the winding hot spot is the main factor contributing to the transformer aging. Figure A.1 shows the main components for calculating the transformer hot spot temperature. As the figure shows, the hot spot temperature is summation of three temperatures: ambient, top oil temperature rise due to loading, and the hot spot temperature rise. Figure A.2 and A.3 below shows the models used to calculate the top oil temperature rise, and the hot spot temperature rise.

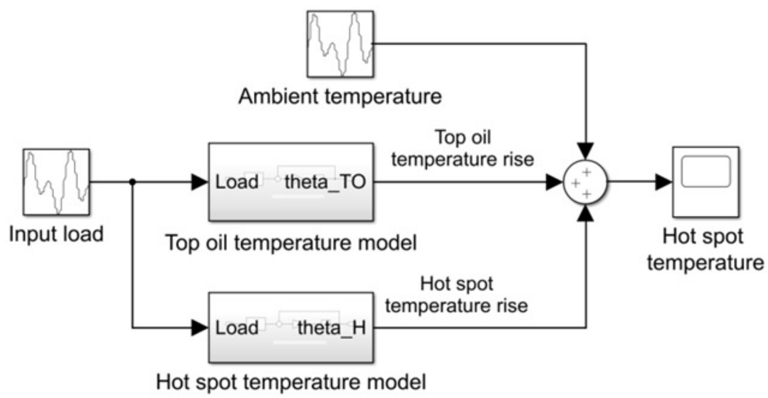

Figure A.1: Model for estimating the hot spot temperature of a transformer

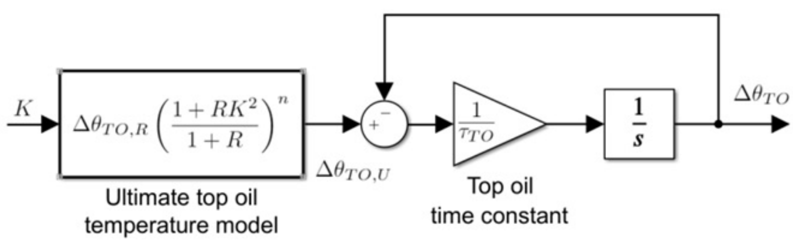

Figure A.2: The simulation model for top oil temperature rise

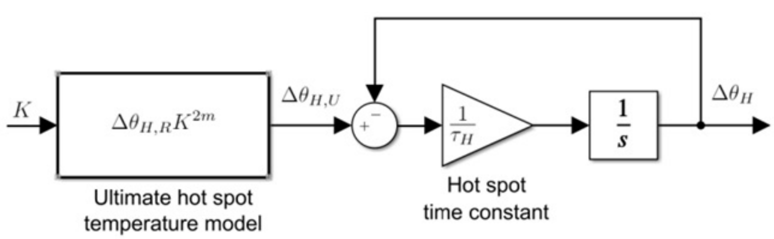

Figure A.3: The simulation model for hot spot temperature rise

Note that in the model the ambient temperatures and load profile are system inputs. Once the hot spot temperature is available, one can calculate the transformer loss of life as follows.
The relation between the power transformer lifetime and the hot spot temperature is captured by:

$$L_{pu} = Ae^{\frac{B}{\Theta_H + 273}} \tag{1}$$

where L_{pu} is the per unit life of the transformer; Θ_H is the hot spot temperature, in ℃; A and B are some constant coefficients. According to [2], we have $A = 9.810^{(} - 18)$ and $B = 15000$. At the referential temperature 110 ℃, we have $L_{pu} = 1$.

The aging acceleration factor F_{AA} is generally used to evaluate the relative aging level. The F_{AA} is defined as

$$F_{AA} = e^{\frac{15000}{110+273} - \frac{15000}{\Theta_H + 273}} \tag{2}$$

This equation shows that the transformer encounters an above-average acceleration over the referential temperature and a below-average acceleration under the reference. Over the given load cycle T, the loss of life can be calculated by integrating F_{AA} over time, i.e.,

$$L_f = \int_0^T F_{AA}\, dt \tag{3}$$

The percent of the total loss of life is required to evaluate the economic impact over the load cycle. To determine this value, we need the normal insulation's lifetime (in hours or years) at the referential temperature. In this paper, we assume the power transformer has a normal lifetime of 180000 hours or 20.55 years over the referential temperature [2]. Letting L be the normal (total) lifetime of the transformer, then the percent loss of life is the percent loss of life is

$$LOL = \frac{L_f}{L} \times 100\% \tag{4}$$

SAMPLE CASE

To illustrate the process, consider a substation transformer of 15 MVA. The parameters used to calculate the top oil temperature rise and hot spot temperature rise are given in Table A.1. These parameters are from [7], which are close to the settings of our 15 MVA transformer.

Table A.1: PARAMETERS FOR TRANSFORMER THERMAL MODELS

Rated top oil rise over ambient temperature $\Delta\Theta_{TO,R}$	38.3 ℃
Rated hot spot rise over top oil temperature $\Delta\Theta_{H,R}$	23.5 ℃
Ratio of load loss to no load loss R	5
Top oil time constant τ_{TO}	114 min
Hot spot time constant τ_H	7 min
Exponent n	0.9

The load profile and the ambient temperatures are required to calculate the transformer hot spot temperature. We consider a one-year period as the basic load cycle, with minute-level input data. A one-year minute-level load profile in kVA is shown in figure A.4.

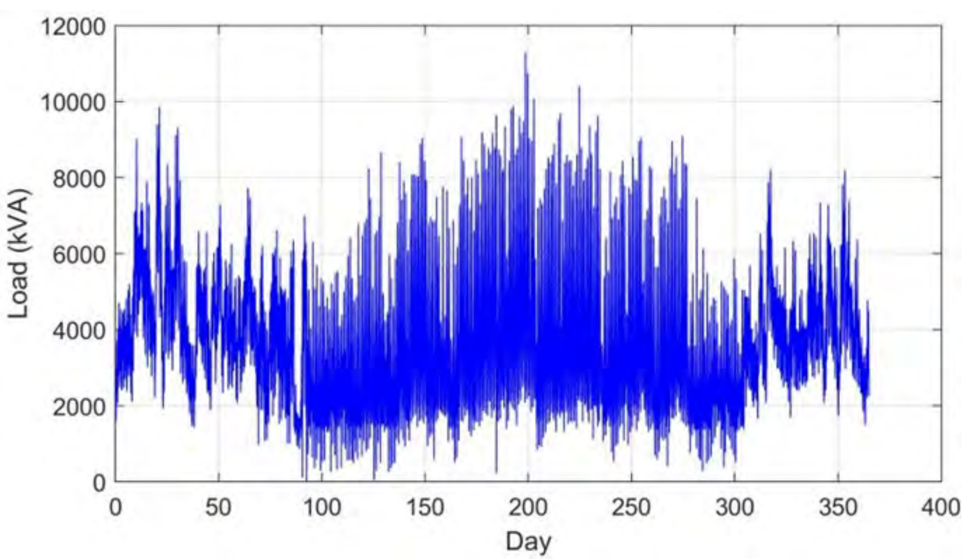

Figure A.4: A one-year load profile

A one-year temperature profile in 2019 of Durham, North Carolina is used and is shown in figure A.5. The original hourly temperature data has been interpolated into the minute-level profile.

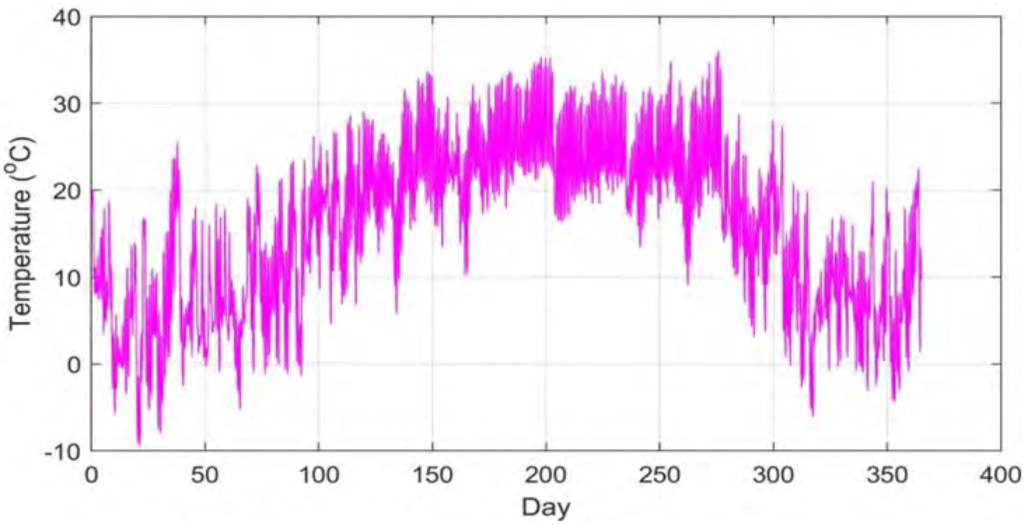

Figure A.5: A sample of one-year minute-level temperature profile

The transformer cumulative loss of life under the given loading and temperate conditions is estimated using the model and it is given in figure A.6. We can see that the cumulative loss of life increases rapidly from day 150 to day 270 due to higher hot spot temperature. On the other days, the cumulative loss of life increases slowly due to the low hot spot temperature.

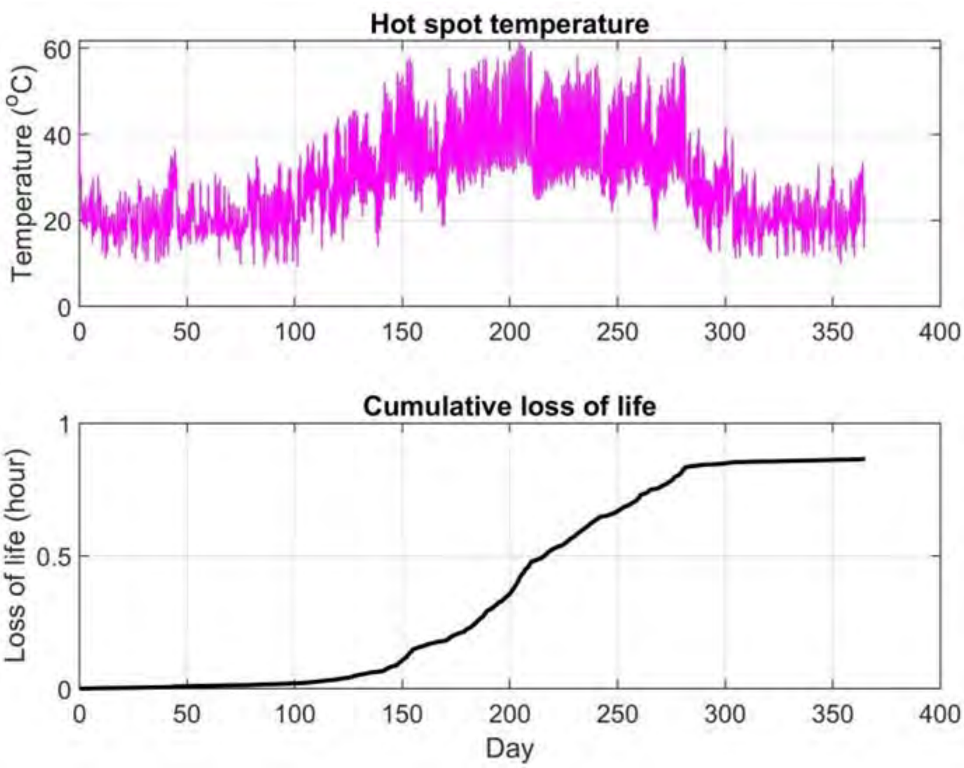

Figure A.6: Transformer hot spot temperature and loss of life

Appendix II

Overload Screening Algorithm

Since most conductors / equipment have two overload rating, i.e., a short term overload rating (emergency rating) and a long term overload rating (normal rating), the following algorithm is used to screen for equipment overloads:

1. If line section or equipment loading $>$ 0.95 normal rating:
   (a) If any single event overload duration $>$ 60 mins, then classify as overload
   (b) If any single event overload duration $<=$60 mins:
      i. If line section or equipment loading $>$ 0.95 emergency rating, then classify as overload

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[4] "IEEE Guide for Loading Mineral-Oil-Immersed Transformers," *IEEE Std C57.91-1995*, pp. 1–112, 1995.

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Appendix 3

REPORT

Distributed Generation Cost-of-Service Stakeholder Report

June 18, 2021

Authored By:

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On June 14, 2019, the North Carolina Utilities Commission issued an Order, under docket E-100 Sub 101, requiring Duke Energy Progress, LLC and Duke Energy Carolinas, LLC to "file testimony in their next general rate case applications regarding the benefits that distributed generators are receiving from the Utility's System, estimating their share of related costs, and providing options for recovering those costs from distributed generators." In the months following the Order, Duke Energy engaged North Carolina Advanced Energy Corporation (Advanced Energy) for stakeholder assistance and the FREEDM Systems Center at North Carolina State University to conduct a cost-of-service study.

Advanced Energy hosted and facilitated the first stakeholder meeting on December 6, 2019, from 9 a.m. to 2 p.m. The meeting was held at Advanced Energy's offices on North Carolina State University's Centennial Campus. Over 400 industry stakeholders were invited to participate. It was important to invite a range of stakeholders to gather feedback from various perspectives. Advanced Energy was pleased to have 38 stakeholders physically present at the meeting and an additional 12 attending virtually. The organizations represented included the following:

- NC Public Staff
- North Carolina Sustainable Energy Association
- Duke Energy
- North Carolina State University
- North Carolina Electric Membership Corporation
- North Carolina Clean Energy Business Alliance
- Southern Environmental Law Center
- Vote Solar
- Renewable Energy Developers
- National Renewable Energy Laboratory
- Appalachian Voices

The purpose of the initial stakeholder meeting was to give background to stakeholders on the topic and to solicit feedback on the general direction Duke Energy planned to pursue to satisfy the Commission's Order. Advanced Energy's role was to facilitate a collaborative process in which stakeholders would have a place to voice their thoughts, suggestions and concerns.

To give stakeholders a foundational understanding of ratemaking, James McLawhorn with the NC Public Staff delivered a ratemaking 101 presentation. Nate Finucane with Duke Energy then presented on the cost-of-service methodology. Advanced Energy next led a group activity where each table of attendees reflected on targeted questions designed to encourage participants to think through the costs and benefits of distributed generation on the grid. Each group had a diverse set of stakeholders so that multiple perspectives were represented, and there was a scribe assigned to each table to record feedback.

After the meeting, Advanced Energy compiled and organized the feedback and then met with the Duke Energy and FREEDM Systems Center teams to discuss it and determine next steps. Many questions came out of the first meeting, including the following:

- How is the study team going to account for the diversity of distributed generation?
- Are all of the costs worth trying to quantify?
- Should there be an entirely new customer class for distributed generation?
- What is the overlap between this effort and ISOP (Integrated System and Operations Planning)?
- What are all of the costs and fees currently being collected for distributed generation?
- How do you fairly allocate costs considering future growth?

The Duke Energy, FREEDM Systems Center and Advanced Energy teams considered these questions and other stakeholder comments. There was a lot of conversation about the scope of the study during the stakeholder meeting. Following this meeting, the FREEDM Systems Center study team started benchmarking the study based on relevant reports. It also conducted interview sessions with Duke Energy engineering staff to discuss field experience with distributed generation impacts on distribution and substation equipment.

The FREEDM Systems Center study team took the input from the initial stakeholder meeting as well as the Duke Energy interview sessions and literature review and drafted a framework for estimating distributed generation cost of service. This framework outlined the specific costs and benefits that could be quantified based on recent distributed generation valuation studies.

The study team spent the rest of 2020 running an initial cost estimation using simulations of a standardized test circuit using actual PV production and customer load data. The results from the case study were presented at the second distributed generation cost-of-service stakeholder meeting on February 25, 2021.

The second meeting was held virtually, with 37 stakeholders present. The first half of the meeting featured a presentation from the FREEDM Systems Center's Dr. Mesut Baran on the cost estimation case study. The second half focused on cost recovery options, with presentations from Nate Finucane and Morgan Beveridge of Duke Energy.

Stakeholders had an opportunity to ask questions and provide feedback after each presentation and were also given two weeks to offer feedback via an online form. Stakeholders had less feedback than they did after the first meeting, and most of it indicated agreement over the general direction the study team is taking to estimate the costs and benefits associated with distributed generation on the grid.

As there were no major objections from stakeholders, the study team is currently working on running cost estimations on actual Duke Energy feeders. The team was planning to host a third large stakeholder meeting but has since decided against that due to the general agreement on the direction of the study and only minor updates since the second stakeholder meeting. No additional large stakeholder meetings are expected at this time.