A GENERAL METHOD FOR SIZING BATTERY ENERGY STORAGE SYSTEMS FOR USE IN MITIGATING PHOTOVOLTAIC FLICKER

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by

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The undersigned, appointed by the dean of the Graduate School, have examined the thesis entitled

A GENERAL METHOD FOR SIZING BATTERY ENERGY STORAGE SYSTEMS FOR USE IN MITIGATING PHOTOVOLTAIC FLICKER

presented by William Noah Wills,

a candidate for the degree of master of science,

and hereby certify that, in their opinion, it is worthy of acceptance.

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***Abstract*:**

A method for sizing battery energy storage (BES) systems for use in mitigating voltage flicker caused by solar intermittency in photovoltaic generation was developed. The method creates a "design day" from existing solar data and designs the power and energy requirements for a BES system that can help a photovoltaic facility mitigate flicker caused by solar activity associated with the design day. An economic analysis of lead-acid and lithium-ion options for the BES was also developed. The method was then applied to a proposed photovoltaic project in the Midwestern United States.

1 Introduction

Renewable energy technology is advancing, with the share of energy generation from renewable sources growing[1]. One renewable energy type that has caught the public imagination is solar power, particularly in the form of photovoltaics (PV). Photovoltaics (PV) cells directly convert solar energy into electrical energy by taking advantage of photon and electron interactions in semi-conductive materials in a process that works in the reverse of that of light emitting diodes [2].

PV systems have many different applications, from powering small electronic devices to residential use to utility-scale grid-connected generation. PV systems are often used with batteries to store generated electricity. Residential PV use, so called "rooftop" solar, is becoming increasingly popular for its ability to offset electricity costs and for its environmental friendliness.

PV generation can be both off-grid, or "islanded," and grid-connected. Islanded generation refers to set-ups where the PV resources are not connected to the local electric utility's other generation and transmission resources. Grid-connected PV resources can include rooftop solar as well as utility-scale projects overseen by electric utility companies. These utility-scale projects can be in the megawatt range, much larger than rooftop solar projects.

PV generation does present certain challenges, however. For starters, it depends on solar irradiance, which is only available for part of the day, and can be undependable due to the climate and weather conditions. While PV can generate energy when clouds are overhead, solar intermittency caused by moving clouds can cause rapid changes in power. For grid-connected PV use, this can cause power quality issues [3].

These challenges extend to rooftop solar power as well. Rooftop solar, even when it is grid-connected, is not directly controlled by utilities. Some utilities may want to avoid power quality issues coming from rooftop solar because of this and build their own solar resources. While this means that utilities can serve customers' desire for solar power, it also means that utilities must deal with power quality issues stemming from solar intermittency.

1.1 Utility-scale PV Issues

Intermittent solar activity disrupts PV generation. For grid-connected, utility-scale PV installations, this is not necessarily a problem, because utilities generally have other sources of electricity generation. However, the intermittency can cause fast-ramping voltage excursions. These voltage deviations can cause flicker (discussed below) and stress on substation equipment.

One key piece of equipment involved in this issue is the load tap changer (LTC). LTCs adjust the turns ratio on substation transformers, allowing the electrical grid to respond to changes in generation and load[4]. LTCs are particularly important in grid-connected PV installations (both rooftop and utility-scale). One of the consequences of solar intermittency is that LTCs serving PV installations can suffer from overuse by responding to the sometimes-rapid changes in generation.

1.2 Flicker

For utility customers, voltage deviation manifests itself as a flickering of incandescent lights, hence voltage deviation is called "flicker."[5] The acceptability of voltage flicker is measured by the GE Flicker Curve, an industry tool, seen in Figure 1.1. It plots percent voltage change ("flicker") against frequency of deviations, and has two curves on it, one representing flicker visible by humans and one representing flicker that is irritable to humans. These curves are based on industry research and used based on electric utility industry convention rather than law. [6]

Voltage deviation has always been an issue in electrical grids. Between the 1920's and the 1950's, several studies on voltage deviation perception were performed and culminated in flicker curves developed by General Electric (GE) and Consolidated Edison (Con Ed)[6]. GE's curve is today widely used in the utilities industry and used in the Institute of Electrical and Electronics Engineers' (IEEE) standards ([7, 8]) as a guide to what amount of voltage deviation in the customer's electric supply is likely to cause customer irritation and complaint.

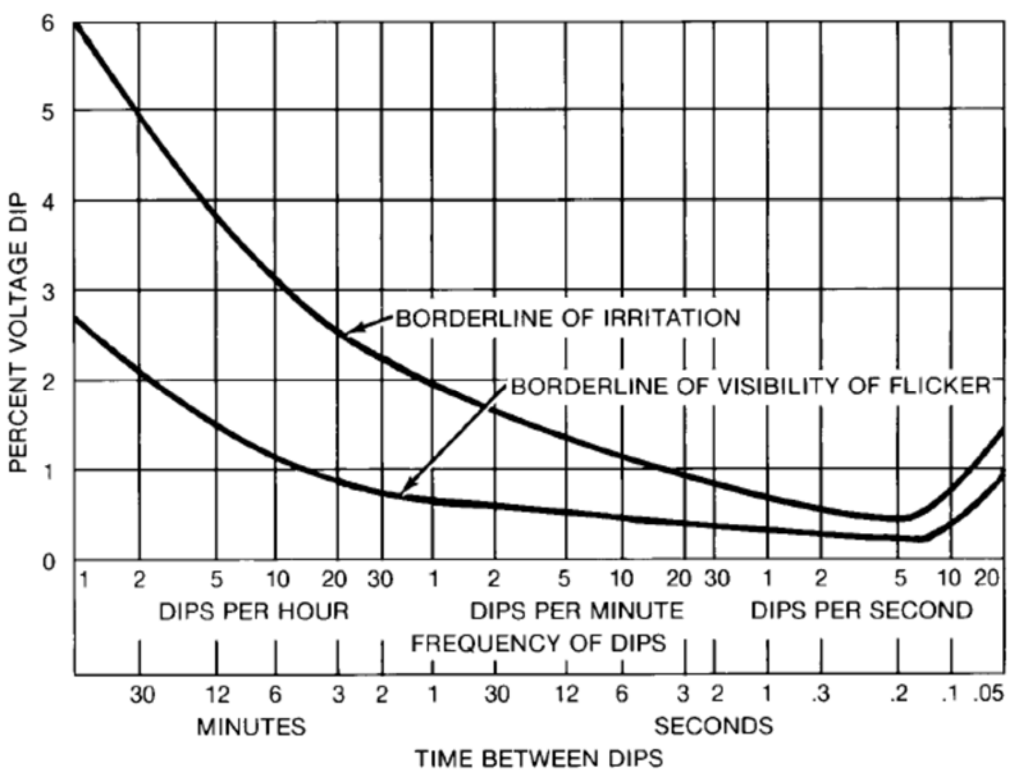

Figure 1.1 - GE Flicker Curve

It should be noted that the GE Flicker Curve assumes incandescent lightbulb use. Per the *Energy Independence and Security Act of 2007* (EISA), incandescent lightbulb use has been severely limited. Among other standards, the Act bans the manufacture of household incandescent lightbulbs due to their inefficiency [9, 10]. Because the GE Flicker Curve is based on incandescent lamps, and because electric utilities typically use the Curve as their flicker limit, utilities may be using an inaccurate and non-useful tool for flicker standards. However, the GE Flicker Curve is still the industry standard, and is used throughout this work.

1.3 __Battery Energy Storage Systems__

One possible solution to flicker caused by solar intermittency in PV generation is to use battery energy storage (BES) to help support the PV installations. Battery energy storage systems (BESS) can be connected to PV installations to "fill in" the gaps in generation caused by solar intermittency. The BESS would be discharged as needed and recharged regularly. These BESS would need to be scalable up to the megawatt-hour range, be capable of fast and repeatable discharges, and have a long lifetime (that is, capable of several discharges and recharges).

1.4 __Description of Problem__

In this work, the problem studied will be how to mitigate voltage flicker that is caused by solar intermittency in photovoltaic installations. The method chosen will be to use battery energy storage systems. The main goals will be to prevent flicker in customer loads and to relieve stress and maintenance costs on equipment, particularly load tap changers.

2 Literature Review

This literature review seeks to detail extant industry practices associated with smoothing of utility scale photovoltaic facility output. Two groups of works were reviewed: literature related to general analysis of PV flicker, and literature related to using BES systems for PV flicker mitigation. For literature related to general analysis of PV flicker, [5, 11-13] were the main works reviewed. For literature related to using BES systems to mitigate PV flicker, [14-16] were the main works reviewed. [3, 17-20] and [8, 21-25] were reviewed but determined to not be of immediate use.

2.1 General Texts on PV Flicker

The following is an analysis of the relevant elements of the four texts ([5, 11-13]) that deal with general analysis of PV flicker that were most important or useful in the investigation so far.

One IEEE standard was found, [5], that includes tools for the analysis of PV flicker. Other works ([11-13]) draw upon the analysis tools in the standard, expand upon those tools, and show the broad usage of the standard's analysis tools.

2.1.1 IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems [5]

The standard is concerned with the practice of measuring and analyzing voltage flicker present in power systems. Many practices in the standard are descended from international standards, particularly from the International Electrotechnical Commission (IEC).

Two related metrics mentioned in the standard are the short term and long term flicker severities, P_{ST} and P_{LT}, respectively. P_{ST} is shown in Equation (2.1) (called "Equation (1)" in [5]):

$$P_{ST} = \sqrt{0.0314 * \mathrm{P}_{0.1} + 0.0525 P_{1s} + 0.0657 P_{3s} + 0.28 P_{10s} + 0.08 P_{50s}} \tag{2.1}$$

where, the percentages $P_{0.1}$, P_{1s}, P_{3s}, P_{10s}, and P_{50s} are the flicker levels that are exceeded 0.1, 1.0, 3.0, 10.0, and 50.0 percent of the time, respectively. P_{1s}, P_{3s}, P_{10s}, and P_{50s} are calculated thus in Equations (2.2), (2.3), (2.4), and (2.5), respectively (called Equations "(2)", "(3)", "(4)", and "(5)," respectively, in [5]).

$$P_{1s} = \frac{P_{0.7} + P_1 + P_{1.5}}{3} \tag{2.2}$$

$$P_{3s} = \frac{P_{2.2} + P_3 + P_4}{3} \tag{2.3}$$

$$P_{10s} = \frac{P_6 + P_8 + P_{10} + P_{13} + P_{17}}{5} \tag{2.4}$$

$$P_{50s} = \frac{P_{30} + P_{50} + P_{80}}{3} \tag{2.5}$$

where, the terms of style P_X represent the flicker levels that are exceeded X% of the time. Equation (2.6) (called "Equation (6)" in [5]) gives P_{LT}, which is calculated using 12 consecutive P_{ST} values:

$$P_{LT} = \sqrt[3]{\frac{1}{12} * \sum_{j=1}^{12} P_{ST\,j}^{3}} \tag{2.6}$$

The P_{ST} and P_{LT} values are likely useful tools for evaluating the success a BES system would have in mitigating voltage flicker from PV intermittency.

The standard also contains acceptable levels of voltage flicker. These levels can likely be used in conjunction with the P_{ST} and P_{LT} values.

The standard includes the GE Flicker Curve (Figure 1.1, called “Fig. 1” in [5]).

2.1.2 J. Hernandez, M. Ortega, and P. Vidal [11]

The paper summarizes the state of knowledge on analyzing PV distributed generation issues, including flicker. The paper mentions the P_{ST} and P_{LT} values mentioned in [5]. It should be noted that the paper is written with the assumption of International Electrotechnical Commission (IEC) standards (and thus not IEEE). However, the fact that the P_{ST} and P_{LT} values have broad usage gives weight to their usefulness.

2.1.3 Y. S. Lim and J. H. Tang [12]

The paper details an experiment to study the effects of PV intermittency on voltage flicker in Malaysia, a country particularly susceptible to PV intermittency. The paper also proposes a solution to PV flicker in the form of a dynamic load controller.

The paper uses the P_{ST} and P_{LT} values and generalizes them, as shown in Equations (2.7) and (2.8) (called Equations “(2)” and ”(3),” respectively, in [12]), to:

$$P_{ST} = P_{ST0} * \frac{d}{d_0} = \frac{d}{d_0} \tag{2.7}$$

where d is the average number of voltage changes in a minute and d_0 is the relative voltage change that produces P_{ST0} = 1.0.; and:

$$P_{LT} = \sqrt[3]{\sum_{i=1}^{N} \frac{\left(P_{ST}^{i}\right)^3}{N}} \tag{2.8}$$

The paper also explains the near linear relationship between change in PV power output and voltage change.

2.1.4 S. Zhu, J. Zhang, X. Qin, and C. Niu [13]

The article evaluates new testing techniques for evaluating flicker, harmonics, inter-harmonics, and high frequency components in large scale PV installations connected to medium-voltage grids in China. The article's method of analysis involves a "fictitious grid". This analysis includes a version of the P_{ST} value, as shown in Equation (2.9):

$$P_{ST} = P_{ST,fic} \times \frac{S_{k,fic}}{S_n} \tag{2.9}$$

where $P_{ST,fic}$ is the flicker emission value of a fictitious grid, $S_{K,fic}$ is the three-phase short circuit apparent power of the fictitious grid, and S_n is the rated apparent power of PV station. This version of the P_{ST} value draws from the IEC standard that [5] is a counterpart to.

2.2 Texts Specific to BES Use for PV Flicker

The following is an analysis of the relevant elements of the three texts ([14-16]) that relate to BES use for PV flicker that were most important or useful in the investigation so far. None of the reviewed works directly answered the study's objective. There is one withdrawn IEEE standard, [14], that relates directly to the study's objective. [15] and [16] address BES sizing while discussing BES control methods.

2.2.1 IEEE Recommended Practice for Sizing Nickel-Cadmium Batteries for Photovoltaic (PV) Systems [14]

No documentation on why the standard was withdrawn could be obtained. However, the standard's method for determining battery size is based on the assumption that the battery is to be used to support the load when the PV cannot. It is assumed that the standard was discontinued because it does not address battery use in solar intermittency.

None of the current IEEE standards related to BES use in photovoltaic intermittency mitigation cover grid-connected systems.

2.2.2 W. Jin, Z. Xie, and B. Li [15]

The article analyses a PV installation in China and determines an appropriate BES system and control strategy to mitigate voltage flicker.

Section II of the article indicates that there is a standard requirement in China that power variation in PV power be analyzed in 1 minute and 10 minute intervals. This is seen throughout the paper.

Section III of the article deals with BES capacity. The general approach is to find the power requirement and the energy capacity requirement for the BES.

Figures Figure 2.1 and Figure 2.2 (Figures "4" and "5" in [15]) deal with the power requirement. Figures Figure 2.1 and Figure 2.2 show power values versus the percentage of the time that power value occurs. Figure 2.1 is the one minute and 10 minute values and Figure 2.2 is the combined one minute and 10 minute values. Both figures have a near

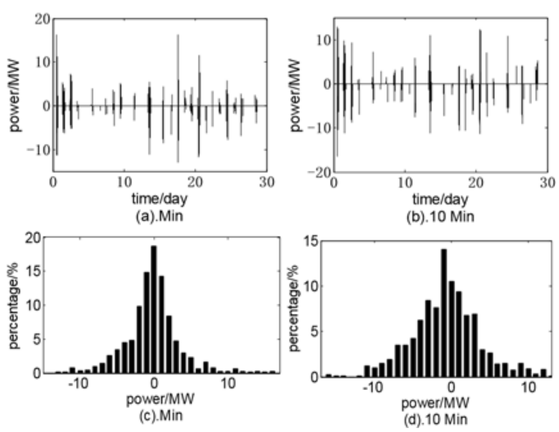

Figure 2.1 - Statistical graph of 1 minute and 10 minutes time interval BESS power output statistics ("Fig. 4" in [6])

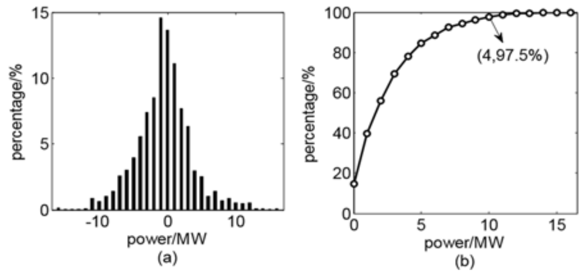

Figure 2.2 - Statistical graph of all BESS power ("Fig. 5" in [6])

normal distribution around zero. The BES power requirement is then the range of Figure 2.2, 10MW.

Figure 2.3 ("Fig.6" in [15]) presents the energy vs. time graphs for each interval. From Figure 2.3, the paper derives the energy ranges [E_0-3.12, E_0+0.54] and [E_0-15.14, E_0] for the 1 minute and 10 minute intervals, respectively, where E_0 is the initial value of the BES. A state of charge range is given as [20%, 80%]. The paper then presents 6.10 MWh and 25.23 MWh as the BES energy capacity (termed E_{cap} here) for the 1 minute and 10 minute intervals, respectively. The values for E_{cap} seem to be derived from:

$$E_{cap} = \frac{(15.14+0)}{(.8-.2)} = 25.23$$

and

$$E_{cap} = \frac{(3.12+0.54)}{(.8-.2)} = 6.10$$

More generally, for energy range [E_0-E_m, E_0+ E_n] and state-of-charge range [r_{min}, r_{max}], E_{cap} and E_0 are:

$$E_{cap} = \frac{(E_m+E_n)}{(r_{max}-r_{min})} \tag{2.10}$$

$$E_0 = E_{cap} * r_{max} - E_n = E_{cap} * r_{min} + E_m \tag{2.11}$$

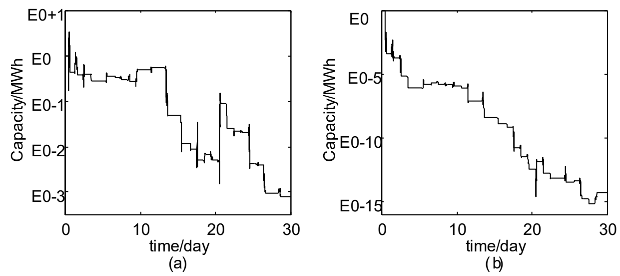

Figure 2.3 - The curves of BESS energy change ("Fig. 6" in [6])

The power values in Figures Figure 2.1 and Figure 2.2 appear to be the difference between PV power and grid power, while Figure 2.3 appears to show the difference between the PV energy generation and the grid energy consumption. Since Figure 2.3 shows the energy value increasing and decreasing, it is concluded that the figures show a difference in energy and power consumption or generation.

2.2.3 M. Z. Daud and A. Mohamed [16]

The paper is concerned with a control method for a PV/BES system. The method has three modes of operation. "Mode I" is the grid-connected low fluctuation mode, shown in Equation (2.12) (called "Equation (1)" in [16]):

$$P_{G,ref} = P_{PV} - P_L \tag{2.12}$$

where $P_{G,ref}$ is the grid power, P_{PV} is the photovoltaic power and P_L is the load power. "Mode II" is the grid-connected high fluctuation mode, shown in Equation (2.13) (called "Equation (2)" in [16]):

$$P_{BES,ref} = P_{SET} - P_{PV} \tag{2.13}$$

where P_{SET} is the power smoothing set point and $P_{BES,ref}$ is the reference power discharged from the BES. "Mode III" is the emergency mode, including non-grid connected mode. Non-grid connected mode is given by Equation (2.14) (called "Equation (3)" in [16]):

$$P_{BES,ref} = P_L - P_{PV} \tag{2.14}$$

The remaining energy level (*REL*) is the feedback signal used to control the BES state of charge. *REL* is given by Equation (2.15) (called "Equation (4)" in [16]):

$$REL = C_{BES} - \int P_{BES}\,\mathrm{dt} \tag{2.15}$$

where C_{BES} is the BES capacity. Figure 2.4 (called "Fig. 3" in [16]) gives the control scheme. The scheme includes the parameters T_{SOC}, the SOC time constant, M, the SOC margin rate, and α, a coefficient defined by Equation (2.16) (called "Equation (5)" in [16]) as:

$$\alpha = \frac{C_{BES}\,(1-2\,M)}{T_{SOC} \times P_{PV\,rated}} \tag{2.16}$$

2.3 Texts Concerning Battery Lifetime Prediction

The following is an analysis of the relevant elements of the three texts ([26-28]) that deal with battery lifetime prediction. While battery lifetime prediction is addressed in Section 3.5, the method described is very basic. The texts discussed in this section are sophisticated

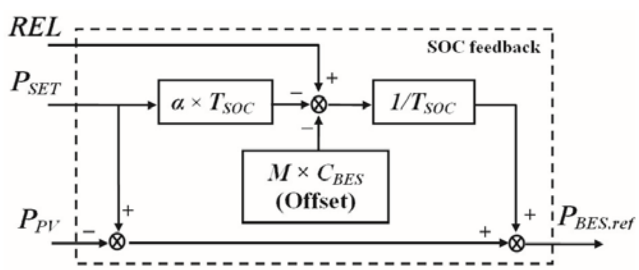

Figure 2.4 - SOC-FB control scheme for BES ("Fig. 3" in [7])

treatments of battery lifetime prediction, but out of the scope of this project. More sophisticated battery lifetime prediction is a good "next step" for this project, as potential battery lifetimes inform BESS purchases and projects.

2.3.1 D. U. Sauer, J. Schiffer, et al

Of interest is the work of D. U. Sauer et al., whose body of work involves battery use in renewable energy systems. Sauer's more recent work, particularly [26, 27], involves lifetime prediction for battery energy systems.

Sauer et al.'s prediction model is based on the internal battery chemistry, specifically the grid corrosion on the positive electrode and the degradation of the active material. The model also takes into account acid stratification, gassing, and the lead sulfate crystal structures. The model continuously multiplies the Ah throughput by a weight factor based on depth-of-discharge, current rate, existing acid stratification, and the time since the last charging.[27]

2.3.2 R. Dufo-López, J. M. Lujano-Rojas, J. L. Bernal-Agustín [28]

The work evaluates three different battery lifetime prediction models, including Sauer et al.'s ([27]). The three models are the Equivalent Full Cycles to Failure, Rainflow Cycle Counting, and the Weighted Ah-throughput (Sauer et al.'s model). The work uses each method to predict the battery lifetime of two battery systems, an off-grid household PV system, and an alarm system, and compares the predicted lifetime with the actual lifetime of the two systems. The work finds that Sauer's model is the most accurate model.

3 Method

The described method consists of characterizing a "design day," determining the expected level of flicker the system will experience during the design day, determining what power and energy requirements are needed to mitigate the expected flicker, and determining the most economical battery type to use.

Table 3.1 shows the parameters and terms that will be used throughout.

Table 3.1 - Parameters and Terms

Term	Description	Units	Note
V_{Δ}	Percent voltage deviation	%	
P_{PV}	Solar power deviation	MW	
$V_{\Delta R}$	Expected flicker	%	
P_d	Design day power value	MW	
V_R	Flicker that is mitigated	%	
V_C	Percent voltage change at design day frequency	%	Using GE Flicker Curve
b	Acceptable point below flicker curve	%	Using GE Flicker Curve
P_R	Battery Power requirement	MW	
$C_{nominal}$	Nominal battery energy requirement	MW-h	
f_d	Design day frequency	Hour^{-1}	
T_d	Design day dip duration	hour	
C_{actual}	Actual needed battery energy requirement	MW-h	
d	Design depth of discharge	%	
L	End of life depth of discharge	%	
n_{ex}	Expected number of recharge cycles	-	
d_{ex}	Expected depth of discharge	%	
C_{ex}	Expected daily energy usage	MW-h	

3.1 Design Day Characterization

The "design day" is the hypothetical day that a BES system supporting a photovoltaic station must be designed to accommodate. It represents a "worst case" scenario while still being possible. The design day is derived from solar data taken in the area of the PV facility. The design day parameters are the dip depth (P_d), the dip frequency (f_d), and the dip duration (T_d). Appropriate, predictive statistical analysis is used to determine reasonable values for the design day characteristics.

3.2 Determination of Expected Flicker Severity

Power flow analysis is done to find the relationship between the solar power deviation and the percent voltage deviation in the load, and thus the expected magnitude of the voltage flicker. This analysis can yield a polynomial approximation of the relationship between the solar power deviation, and the percent voltage deviation. Equation (1) shows the relationship in the form of an *n* degree polynomial:

$$V_\Delta = a_n * P_{PV}^n + a_{n-1} * P_{PV}^{n-1} + \cdots + a_0 \tag{1}$$

where V_Δ is the percent voltage deviation, P_{PV} is the solar power deviation, and a_n is a constant. Equation (1) can be used with a power value to calculate the corresponding flicker value, and vice-versa, as will be seen in the next section.

3.3 Determination of Battery Requirement

The expected flicker level, $V_{\Delta R}$, and the design day frequency, f_d, are compared to the flicker curve (Figure 1.1) to determine the acceptability of the expected flicker. If the expected flicker is above the flicker curve at the design day frequency, the flicker is determined to be unacceptable. An acceptable flicker level is then chosen below the flicker curve at the design day frequency per Figure 1.1.

It should be noted that here, "flicker curve" refers to either the visibility curve or the irritability curve on Figure 1.1, depending on the engineer's preference. While flicker above the irritability curve must be mitigated, some utilities may find that any visible flicker will cause customer complaints.

$V_{\Delta R}$ is calculated using Equation (2), which is derived from Equation (1):

$$V_{\Delta R} = a_n * P_d^n + a_{n-1} * P_d^{n-1} + \cdots + a_0 \qquad (2)$$

where P_d is the design day power value.

V_R is the flicker amount that needs to be mitigated. It is a percent voltage change represented by Equation (3).

$$V_R = V_{\Delta R} - b * V_C \qquad (3)$$

where V_C is the percent voltage change on the flicker curve at the design day frequency, and b is the threshold (in percent) below the flicker curve that is chosen to be mitigated.

The battery power requirement, P_R, is calculated by Equation (4) (derived from Equation (1)).

$$V_R = a_n * P_R^n + a_{n-1} * P_R^{n-1} + \cdots + a_0 \qquad (4)$$

Figure 3.1, using example values, illustrates the relationship between $V_{\Delta R}$, V_C, V_R, and the flicker curve. In this example, a 5% voltage deviation at a frequency of 5 dips per minute is mitigated to 90% of the visibility curve. This yields a V_R value of 3.65%.

For the nominal battery energy requirement, $C_{nominal}$, the power requirement, P_R, is multiplied by the design day values for dip frequency (f_d), the dip duration (T_d), and the number of hours observed in a day, given by Equation (5):

$$C_{nominal} = P_R * f_d * T_d * hours \qquad (5)$$

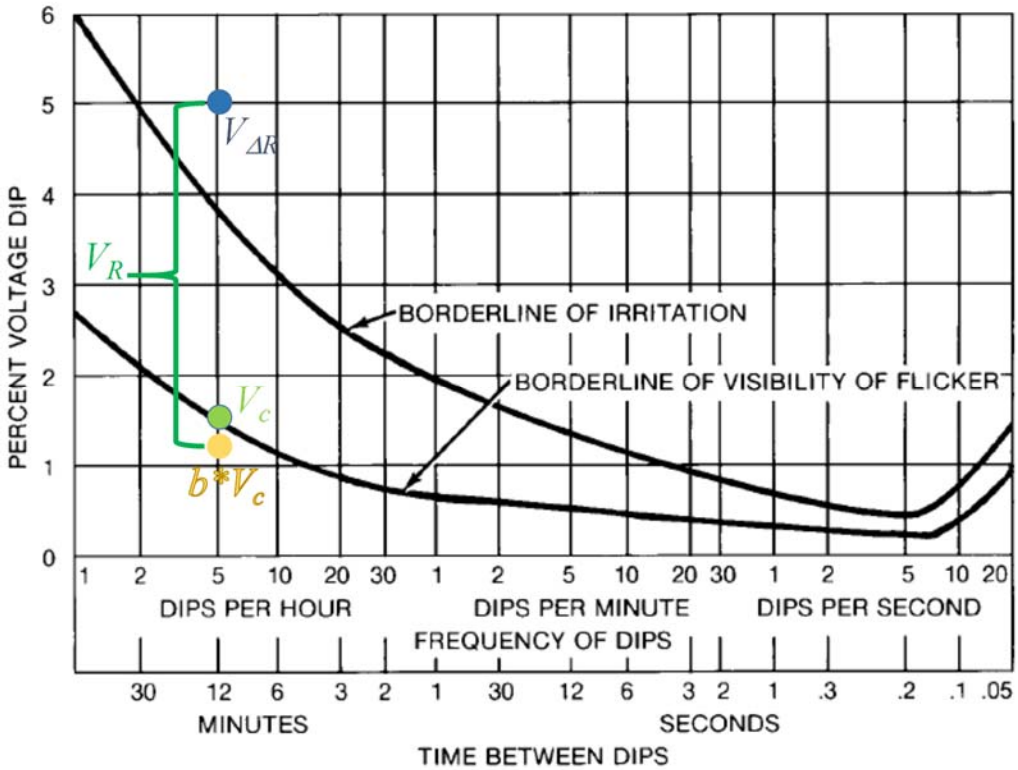

Figure 3.1 - GE Flicker Curve with Flicker Values

It should be noted that the time component of $C_{nominal}$ is not limited by how fast the LTC moves. The amount of time the LTC needs to move (and thus when power from elsewhere in the grid can be drawn) is the shortest amount of time that flicker support can be used. Thus, one might expect the LTC movement time to be used as the time component in $C_{nominal}$ so that the energy value can be minimized. However, part of the goal of the method is to relieve maintenance costs on the LTC. By basing $C_{nominal}$ on the length of the expected dip, the LTC does not need to move as fast, and thus stress and maintenance costs on the LTC can be minimized.

3.4 <u>*Battery Type Analysis*</u>

For every recharge cycle, battery capacity degrades based on the depth of discharge (DoD) of each recharge cycle[29]. Each battery type has an "end-of-life" capacity after which it is no longer considered usable (per industry convention) [29-31] .

To calculate a battery's actual needed capacity, the nominal capacity is divided by a chosen DoD and divided by the percent capacity that is considered the "end-of-life" for that battery chemistry (this ensures that the battery has the requisite capacity at the end-of-life):

$$C_{actual} = \frac{C_{nominal}}{d} * \frac{1}{EoL} \tag{6}$$

where *d* is the chosen DoD (in percent) and *EoL* is the percent capacity that is considered end-of-life for the battery type (in percent). The chosen DoD, *d*, will depend on the desired number of recharge cycles before the BES capacity falls below the end-of-life capacity.

For lead-acid and lithium-ion batteries, the end-of-life capacity is 80% [29-31]. Figure 3.2 shows the relationship between DoD and number of recharge cycles for lead-acid and lithium-ion (specifically lithium iron phosphate) batteries, while Table 3.2 tabulates that data[31, 32].

Table 3.2 - DoD vs. Number of Cycles for Lead-acid and Lithium-ion Batteries

DoD (*d*)	Lead-acid	Lithium-ion
100.0%	500	968
90.0%	590	1198
80.0%	675	1519
70.0%	780	1990
60.0%	950	2716
50.0%	1150	3925
40.0%	1475	6158
30.0%	2050	11008
20.0%	3300	24960
10.0%	7000	101163

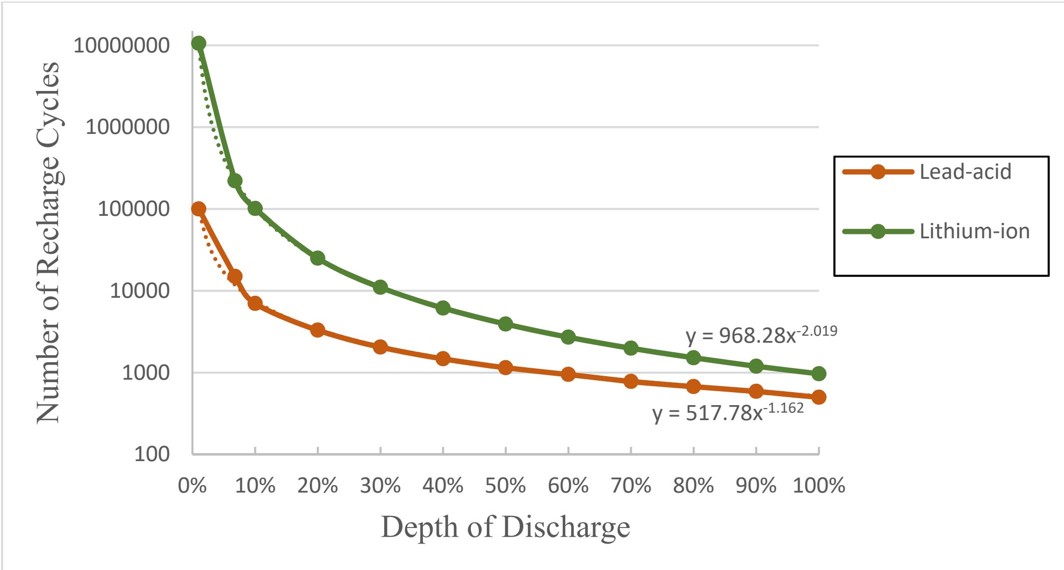

Figure 3.2 - DoD vs. Number of Cycles for Lead-acid and Lithium-ion Batteries

3.5 Economic Analysis

The Equivalent Uniform Annual Cost (EUAC) is used to analyze the project. The EUAC distributes the lifetime cost of the project over each year and is sometimes referred to as the "annual worth" of a project[33]. For this project, the EUAC is the sum of the annual maintenance costs, the product of the up-front cost and an interest factor representing the annual value given the up-front cost, and the product of the up-front cost and an interest factor representing the annual value given the future cost. Equation (7) shows the formula for the EUAC:

$$EUAC = P * \langle A/P\ |i|n_l\rangle + P * \langle A/F\ \mid i\ |n_r\rangle\ + M \tag{7}$$

where the bracketed terms are the interest factors, P is the up-front cost, M is the yearly operation and maintenance cost, i is the interest rate, n_l is the number of interest periods (in years) for the total lifetime of the project, and n_r is the number of interest periods (in years) for each battery replacement (if needed). The first term represents the equivalent annual value of the up-front cost taken over the entire lifetime of the project. The second term represents the equivalent annual value of the battery replacements costs (if such replacements are needed).

The up-front cost, also called "capital" or "principal" cost, is calculated by multiplying the battery energy requirement by the per kilowatt-hour capital cost for that battery type:

$$P = C_{actual} * \left({}^{Capital\ Cost}/_{kW\ *\ hour} \right) \tag{8}$$

Likewise, the yearly operation and maintenance (O&M) cost is calculated by multiplying the battery energy requirement by the per kilowatt-hour yearly operation and maintenance cost for that battery type:

$$M = C_{actual} * \left({}^{O\&M\ Cost}/_{kW\ *\ hour} \right) \tag{9}$$

The number of interest periods for each replacement is the number of expected recharge cycles for the chosen BESS divided by the number of recharges in a year, which is also the number of days in the year that the BESS is used:

$$n_r = \frac{n_{ex}}{\#\ days\ used\ in\ a\ year} \tag{10}$$

where n_{ex} is the expected number of recharge cycles for the replacement period. It is assumed that the BESS will be recharged every day it is used. However, this does not mean that the number of days used in a year is 365. Depending on climate, solar intermittency may only cause power dips (and thus voltage deviation) during part of the year. This is because power demand from utility customers often follows seasonal patterns. It may be that customers demand more power than PV resources can provide (particularly in the Winter), thus solar power deviations will not affect customers (that is, power is being drawn from elsewhere in the grid). It may also be that customers demand so little power compared to PV resources that no amount of day-time solar intermittency will affect customers. Power flow analysis (like that mentioned in Section 3.2) must take into account during what part of the year PV generation and customer demand are close enough for solar intermittency to be a problem.

The number of battery system replacements will be the total project lifetime divided by the replacement time period:

$$Replacements = \frac{n_l}{n_r} \tag{11}$$

The expected discharge can be used to determine the expected number of recharge cycles, n_{ex}, using a DoD vs. number of recharge cycles chart (such as Figure 3.2). The expected discharge, d_{ex}, is:

$$d_{ex} = \frac{C_{ex}}{C_{actual}} \tag{12}$$

where C_{ex} is the expected daily energy usage. For this work, C_{ex} will be assumed to be the average daily energy loss due to dips.

Table 3.3 shows the low-end and high-end costs associated with lead-acid and lithium ion batteries for distribution substation uses (a similar use to the project described herein) [34]. Once the above values are calculated, a table using Table 3.4 as a template can be made and used to make economic decisions. Tables Table 4.5 through Table 4.12 (in Section 4.5) use Table 3.4 as a template.

Table 3.3 - Cost Information for Lead-acid and Lithium-ion Batteries

Battery Type	Low-end Capital Cost ($/kW*h)	High-end Capital Cost ($/kW*h)	Low-end Operation and Maintenance Cost ($/kW*h /year)	High-end Operation and Maintenance Cost ($/kW*h /year)
Lead-acid	511	1211	12	28
Lithium-ion	432	901	7	14

Table 3.4 - Economic Analysis Template

DoD (d)	Battery Capacity (C_{actual})	Expected Discharge rate, d_{ex}	Expected recharge cycles, n_{ex}	Replacements over 30-year lifetime	Capital Cost	O&M Costs	EUAC
100.0%	-	-	-	-	-	-	-
90.0%	-	-	-	-	-	-	-
…	…	…	…	…	…	…	…

4 <u>Case Study</u>

4.1 <u>Problem Overview</u>

A utility-scale, grid-connected 13.5 MW photovoltaic facility is proposed to serve in the Midwestern United States. The electric utility proposing the project (henceforth “Utility”) is concerned that solar intermittency at the facility may cause voltage flicker in the customers served by the facility.

4.2 <u>Design Day Characterization</u>

Data on solar dips at an existing 4.5 MW solar PV installation were collected by the Utility between June and September of 2015. This facility is in the same area as the proposed project and is also owned by the Utility, thus the data can be used to predict solar behavior at the proposed facility. Table 4.1 shows these data and the various statistics associated with dip behavior. These data are used as the basis of the design day for the proposed solar facility. It should be noted that the distributions for dip depth, and dip frequency are near-normal distributions (that is, their distributions approximately follow a “bell curve” shape).

When using descriptive statistics, a useful concept is Chebyshev's Inequality, which states in part, that for any distribution, 75% of values are at least within two standard deviations of the mean, and that 88.9% of values are at least three standard deviations of the mean [35]. That is, 75% is the *minimum* portion of values that is between the mean minus two standard deviations and the mean plus two standard deviations, and likewise for 88.9% of values and three standard deviations, *regardless of the distribution of the values*. A related concept states that for normal distributions (like the solar data herein), 95% of values are within two standard deviations of the mean, and 99.7% of values are within three standard deviations of the mean (this is called the “Empirical Rule” or the “Three Sigma Rule of

Thumb”) [35, 36]. For the dip depth, the mean plus three standard deviations is 14.73 MW, which exceeds the range of the data. Even though the data are not distributed normally (only near normally), this suggests that most of the data are within two standard deviations of the mean (and in excess of what the Chebyshev Inequality stipulates). Because of this, the mean plus two standard deviations was chosen as the design day dip depth value. For uniformity, the mean plus two standard deviations was also used for the design day value for dip frequency. Table 4.2 summarizes these parameters.

4.3 Determination of Expected Flicker Severity

A power flow analysis was done by the Utility using PSS/E software to find the relationship between the solar power deviation and the percent voltage deviation in the load, and thus the expected magnitude of the voltage flicker, shown in Table 4.3.

Figure 4.1 is a graph of percent voltage change vs. solar power deviation, derived from Table 4.3. Using Equation (1) as a guide, a polynomial approximation between the solar power deviation and percent voltage change was made using Figure 4.1:

$$V_{\Delta} = -0.0012 * P_{PV}^2 + 0.3426 P_{PV} - 0.0011$$

Equation (2) is realized as:

$$V_{\Delta R} = -0.0012 * 11.97^2 + 0.3426 * 11.97 - 0.0011 = 3.92$$

Table 4.1 - Statistics on Solar Activity

Day Count	75
Dip Count	557
Peak Depth of Dip (MW)*	
Mean	6.45
Median	6.66
Mode	8.61
Standard Deviation	2.76
Minimum	0
Maximum	13.38
Dip Frequency (per hour)	
Mean	1.24
Median	1.17
Mode	0.67
Standard Deviation	0.77
Range	20
Minimum	1
Maximum	21
Dip Duration (hours)	
Mean	0.27
Median	0.15
Minimum	0.03
Maximum	3.12
Energy loss during Dip (MW-hr)*	
Mean	0.99
Median	0.45
Standard Deviation	1.95
Minimum	0
Maximum	24.75
Daily Average	7.35

*These power and energy values has been scaled by a factor of 13.5/4.5 since the proposed and existing facilities have different power ratings (13.5 MW and 4.5 MW, respectively).

At 11.97 MW, the expected flicker amount, $V_{\Delta R}$, is 3.92%. The Utility believes it will receive customer complaints if the flicker level is above the visibility curve. At 2.78 dips per hour, the expected flicker amount is well above the visibility curve in Figure 1.1 and thus objectionable.

Table 4.2 - Design Day Parameters

	Mean	Standard Deviation	Design Day Parameter
Dip depth (MW)	6.45*	2.76	11.97
Dip Frequency (per hour)	1.24	0.77	2.78
Dip Duration (hours)	0.27	n/a	0.27
Energy Lost per Day (MW-hours)	7.35	n/a	7.35

4.4 Determination of Battery Requirement

The acceptable point below the flicker curve is chosen to be 90% of the visibility curve at a given frequency per Figure 1.1. At 2.78 deviations per hour, the percent voltage change on the curve is approximately 1.9%. Equation (3) is realized as:

$$V_R = 3.92 - .9 * 1.9 = 2.21$$

where 2.21% is the flicker level to be mitigated.

Equation (4) is realized as:

$$2.21 = -0.0012 * P_R^2 + 0.3426 * P_R - 0.0011$$
$$\Rightarrow P_R = 6.6$$

Table 4.3 - Power Flow Analysis Results

Solar Dip (%)	Photovoltaic Power (MW)	Solar Plant Tap Volts (%)	Voltage Deviation (%)
0	13.2	102.5	-
50	6.6	100.3	2.2
80	2.6	99.0	3.5
100	0	98.2	4.3

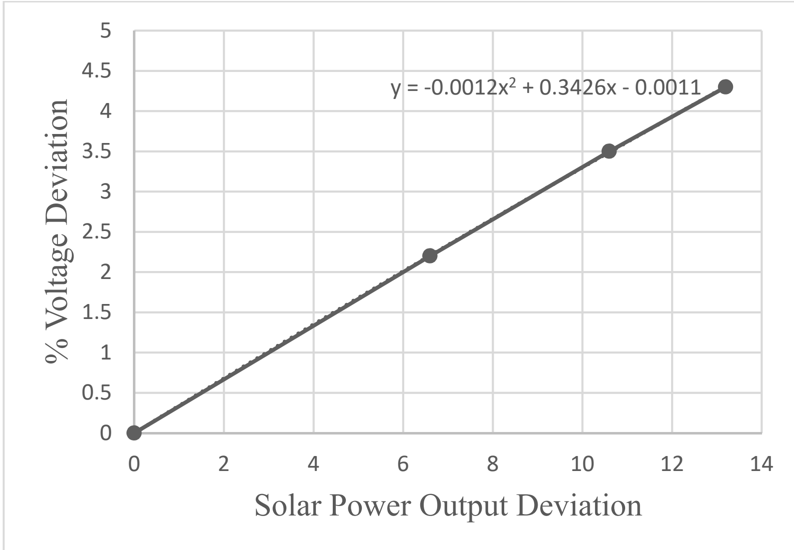

Figure 4.1 - Percent Voltage Deviation vs. Solar Power

where 6.6 MW is the battery power requirement. Taking values from Table 4.2 and using Equation (5), the energy requirement is:

$$C_{nominal} = 6.6 * 2.78 * 0.27 * 6 = 29.72$$

Table 4.4 summarizes the BES system's parameters.

Table 4.4 - BES System Parameters

Term	Value	Units
$V_{\Delta R}$	3.92	%
P_d	11.97	MW
V_R	2.21	%
V_C	1.9	%
b	90	%
P_R	6.6	MW
$C_{nominal}$	29.72	MW-h
f_d	2.78	$Hour^{-1}$
T_d	0.27	Hour
$L_{lead\text{-}acid}$	80	%
$L_{lithium\text{-}ion}$	80	%
n_L	30	years
C_{ex}	7.35	MW-h

4.5 ***Economic Analysis***

The expected daily energy due to dips, C_{ex}, is 7.35MW-h, taken from Table 4.1. The project lifetime, n_L, is 30 years. The number of days used the year, which is used to calculate n_r, is 75. Tables Table 4.5 through Table 4.12 are the economic analyses (based on Table 3.4) for lead-acid and lithium-ion cases and taking into account high-end and low-end capital and O&M costs.

Table 4.6 - Economic Analysis for Lead-acid Batteries for *High-end* Capital and *High-end* O&M Costs

DoD (d)	Battery Capacity (C_{actual})	Expected Discharge rate, d_{ex}	Expected recharge cycles, n_{ex}	Replacements over 30-year lifetime	Capital Cost	O&M Costs	EUAC
100.0%	37.15	19.78%	3403	0.66	$44,988,650	$1,040,200	$4,242,854
90.0%	41.28	17.81%	3846	0.59	$49,987,389	$1,155,778	$4,630,598
80.0%	46.44	15.83%	4410	0.51	$56,235,813	$1,300,250	$5,127,703
70.0%	53.07	13.85%	5150	0.44	$64,269,500	$1,486,000	$5,783,634
60.0%	61.92	11.87%	6160	0.37	$74,981,083	$1,733,667	$6,680,711
50.0%	74.30	9.89%	7614	0.30	$89,977,300	$2,080,400	$7,965,546
40.0%	92.88	7.91%	9868	0.23	$112,471,625	$2,600,500	$9,926,121
30.0%	123.83	5.94%	13785	0.16	$149,962,167	$3,467,333	$13,223,544
20.0%	185.75	3.96%	22081	0.10	$224,943,250	$5,201,000	$19,833,888
10.0%	371.50	1.98%	49410	0.05	$449,886,500	$10,402,000	$39,667,762

Table 4.5 - Economic Analysis for Lead-acid Batteries for *High-end* Capital and *Low-end* O&M Costs

DoD (d)	Battery Capacity (C_{actual})	Expected Discharge rate, d_{ex}	Expected recharge cycles, n_{ex}	Replacements over 30-year lifetime	Capital Cost	O&M Costs	EUAC
100.0%	37.15	19.78%	3403	0.66	$44,988,650	$445,800	$3,648,454
90.0%	41.28	17.81%	3846	0.59	$49,987,389	$495,333	$3,970,154
80.0%	46.44	15.83%	4410	0.51	$56,235,813	$557,250	$4,384,703
70.0%	53.07	13.85%	5150	0.44	$64,269,500	$636,857	$4,934,491
60.0%	61.92	11.87%	6160	0.37	$74,981,083	$743,000	$5,690,044
50.0%	74.30	9.89%	7614	0.30	$89,977,300	$891,600	$6,776,746
40.0%	92.88	7.91%	9868	0.23	$112,471,625	$1,114,500	$8,440,121
30.0%	123.83	5.94%	13785	0.16	$149,962,167	$1,486,000	$11,242,210
20.0%	185.75	3.96%	22081	0.10	$224,943,250	$2,229,000	$16,861,888
10.0%	371.50	1.98%	49410	0.05	$449,886,500	$4,458,000	$33,723,762

Table 4.7 - Economic Analysis for Lead-acid Batteries for *Low-end* Capital and *High-end* O&M Costs

DoD (*d*)	Battery Capacity (C_{actual})	Expected Discharge rate, d_{ex}	Expected recharge cycles, n_{ex}	Replacements over 30-year lifetime	Capital Cost	O&M Costs	EUAC
100.0%	37.15	19.78%	3403	0.66	$18,983,650	$1,040,200	$2,391,609
90.0%	41.28	17.81%	3846	0.59	$21,092,944	$1,155,778	$2,622,032
80.0%	46.44	15.83%	4410	0.51	$23,729,563	$1,300,250	$2,915,303
70.0%	53.07	13.85%	5150	0.44	$27,119,500	$1,486,000	$3,299,452
60.0%	61.92	11.87%	6160	0.37	$31,639,417	$1,733,667	$3,821,148
50.0%	74.30	9.89%	7614	0.30	$37,967,300	$2,080,400	$4,563,728
40.0%	92.88	7.91%	9868	0.23	$47,459,125	$2,600,500	$5,691,658
30.0%	123.83	5.94%	13785	0.16	$63,278,833	$3,467,333	$7,584,116
20.0%	185.75	3.96%	22081	0.10	$94,918,250	$5,201,000	$11,375,571
10.0%	371.50	1.98%	49410	0.05	$189,836,500	$10,402,000	$22,751,137

Table 4.8 - Economic Analysis for Lead-acid Batteries for *Low-end* Capital and *Low-end* O&M Costs

DoD (*d*)	Battery Capacity (C_{actual})	Expected Discharge rate, d_{ex}	Expected recharge cycles, n_{ex}	Replacements over 30-year lifetime	Capital Cost	O&M Costs	EUAC
100.0%	37.15	19.78%	3403	0.66	$18,983,650	$445,800	$1,797,209
90.0%	41.28	17.81%	3846	0.59	$21,092,944	$495,333	$1,961,587
80.0%	46.44	15.83%	4410	0.51	$23,729,563	$557,250	$2,172,303
70.0%	53.07	13.85%	5150	0.44	$27,119,500	$636,857	$2,450,309
60.0%	61.92	11.87%	6160	0.37	$31,639,417	$743,000	$2,830,481
50.0%	74.30	9.89%	7614	0.30	$37,967,300	$891,600	$3,374,928
40.0%	92.88	7.91%	9868	0.23	$47,459,125	$1,114,500	$4,205,658
30.0%	123.83	5.94%	13785	0.16	$63,278,833	$1,486,000	$5,602,782
20.0%	185.75	3.96%	22081	0.10	$94,918,250	$2,229,000	$8,403,571
10.0%	371.50	1.98%	49410	0.05	$189,836,500	$4,458,000	$16,807,137

Table 4.9 - Economic Analysis for Lithium-ion Batteries for *High-end* Capital and *High-end* O&M Costs

DoD (d)	Battery Capacity (C_{actual})	Expected Discharge rate, d_{ex}	Expected recharge cycles, n_{ex}	Replacements over 30-year lifetime	Capital Cost	O&M Costs	EUAC
100.0%	37.15	19.78%	25512	0.088	$33,472,150	$520,100	$2,697,511
90.0%	41.28	17.81%	31559	0.071	$37,191,278	$577,889	$2,997,235
80.0%	46.44	15.83%	40031	0.056	$41,840,188	$650,125	$3,371,889
70.0%	53.07	13.85%	52418	0.043	$47,817,357	$743,000	$3,853,588
60.0%	61.92	11.87%	71556	0.031	$55,786,917	$866,833	$4,495,852
50.0%	74.30	9.89%	103399	0.022	$66,944,300	$1,040,200	$5,395,023
40.0%	92.88	7.91%	162247	0.014	$83,680,375	$1,300,250	$6,743,778
30.0%	123.83	5.94%	290020	0.008	$111,573,833	$1,733,667	$8,991,705
20.0%	185.75	3.96%	657592	0.003	$167,360,750	$2,600,500	$13,487,557
10.0%	371.50	1.98%	2665239	0.001	$334,721,500	$5,201,000	N/A

Table 4.10 - Economic Analysis for Lithium-ion Batteries for *High-end* Capital and *Low-end* O&M Costs

DoD (d)	Battery Capacity (C_{actual})	Expected Discharge rate, d_{ex}	Expected recharge cycles, n_{ex}	Replacements over 30-year lifetime	Capital Cost	O&M Costs	EUAC
100.0%	37.15	19.78%	25512	0.088	$33,472,150	$260,050	$2,437,461
90.0%	41.28	17.81%	31559	0.071	$37,191,278	$288,944	$2,708,290
80.0%	46.44	15.83%	40031	0.056	$41,840,188	$325,063	$3,046,827
70.0%	53.07	13.85%	52418	0.043	$47,817,357	$371,500	$3,482,088
60.0%	61.92	11.87%	71556	0.031	$55,786,917	$433,417	$4,062,436
50.0%	74.30	9.89%	103399	0.022	$66,944,300	$520,100	$4,874,923
40.0%	92.88	7.91%	162247	0.014	$83,680,375	$650,125	$6,093,653
30.0%	123.83	5.94%	290020	0.008	$111,573,833	$866,833	$8,124,871
20.0%	185.75	3.96%	657592	0.003	$167,360,750	$1,300,250	$12,187,307
10.0%	371.50	1.98%	2665239	0.001	$334,721,500	$2,600,500	#NUM!

Table 4.11 - Economic Analysis for Lithium-ion Batteries for *Low-end* Capital and *High-end* O&M Costs

DoD (d)	Battery Capacity (C_{actual})	Expected Discharge rate, d_{ex}	Expected recharge cycles, n_{ex}	Replacements over 30-year lifetime	Capital Cost	O&M Costs	EUAC
100.0%	37.15	19.78%	25512	0.088	$16,048,800	$520,100	$1,564,098
90.0%	41.28	17.81%	31559	0.071	$17,832,000	$577,889	$1,737,886
80.0%	46.44	15.83%	40031	0.056	$20,061,000	$650,125	$1,955,122
70.0%	53.07	13.85%	52418	0.043	$22,926,857	$743,000	$2,234,425
60.0%	61.92	11.87%	71556	0.031	$26,748,000	$866,833	$2,606,829
50.0%	74.30	9.89%	103399	0.022	$32,097,600	$1,040,200	$3,128,195
40.0%	92.88	7.91%	162247	0.014	$40,122,000	$1,300,250	$3,910,244
30.0%	123.83	5.94%	290020	0.008	$53,496,000	$1,733,667	$5,213,658
20.0%	185.75	3.96%	657592	0.003	$80,244,000	$2,600,500	$7,820,487
10.0%	371.50	1.98%	2665239	0.001	$160,488,000	$5,201,000	#NUM!

Table 4.12 - Economic Analysis for Lithium-ion Batteries for *Low-end* Capital and *Low-end* O&M Costs

DoD (d)	Battery Capacity (C_{actual})	Expected Discharge rate, d_{ex}	Expected recharge cycles, n_{ex}	Replacements over 30-year lifetime	Capital Cost	O&M Costs	EUAC
100.0%	37.15	19.78%	25512	0.088	$16,048,800	$260,050	$1,304,048
90.0%	41.28	17.81%	31559	0.071	$17,832,000	$288,944	$1,448,942
80.0%	46.44	15.83%	40031	0.056	$20,061,000	$325,063	$1,630,059
70.0%	53.07	13.85%	52418	0.043	$22,926,857	$371,500	$1,862,925
60.0%	61.92	11.87%	71556	0.031	$26,748,000	$433,417	$2,173,412
50.0%	74.30	9.89%	103399	0.022	$32,097,600	$520,100	$2,608,095
40.0%	92.88	7.91%	162247	0.014	$40,122,000	$650,125	$3,260,119
30.0%	123.83	5.94%	290020	0.008	$53,496,000	$866,833	$4,346,825
20.0%	185.75	3.96%	657592	0.003	$80,244,000	$1,300,250	$6,520,237
10.0%	371.50	1.98%	2665239	0.001	$160,488,000	$2,600,500	#NUM!

5 Conclusion

5.1 Cost Issues

The most obvious conclusion to derive from the economic analysis is that this method is quite expensive. The options with the lowest capital cost, the low-end capital for lithium-ion cases, are about $16 million. A new substation can cost from $1.7 million to $2.6 million depending on size, so using a BESS is much costlier than upgrading substation equipment[37]. The case with the lowest EUAC, the low-end capital and low-end O&M costs for lithium-ion case, is about $1.3 million, which again is likely costlier than substation upgrading, at least on an annual basis. Also, there is no benefit in discharging the BESS less than 100%, because the increase in capital costs always leads to a higher EUAC. There is no annual cost reduction from increasing the lifetime of the BESS if one assumes a 30-year lifetime (a standard lifetime for this type of project).

5.2 General Limitations of the Method

The method is limited by the quality of the data input into it, particularly the power flow analysis and the solar data. The power flow analysis must take into account seasonal patterns in customer load and how that compares to PV power output. The more accurate, nuanced, and predictive solar statistics are, the better.

As mentioned in Section 3.5, solar intermittency may only cause power dips (and thus voltage deviation) during part of the year. This is because solar behavior is climate-based and because power demand from utility customers often follows seasonal patterns. The only relevant power flow analysis is one where the customer load being served by a PV installation is comparable (in power magnitude) to the PV output.

The solar statistics provided for the case study were descriptive, but did not contain any information on correlation. This is significant because this forced the assumption that all values of dip depth could and did appear at all values of dip frequency, and could and did last for all values of dip duration. For example, one could hypothesize that heavier clouds are slower and block irradiance the most, thus associating larger dip depth with slower frequency. If this is the case, then the BESS's power rating (and energy capacity) could be smaller while still mitigating flicker effectively.

5.3 Alternative Solutions

Alternative solutions to mitigating photovoltaic flicker are likely needed. The most obvious alternative solution to BESS use in mitigating PV flicker is to upgrade substation equipment. A higher transformer rating, or additional feeding could serve customer load enough to mitigate the effects of intermittency from a PV installation. In fact, this is the reason why the Utility in the case study does not have similar issues associated with its existing, 4.5 MW installation.

And finally, if a BESS solution is still wanted, alternative charging regimens can be used to lower BESS costs. As shown in the literature review, there is current research on optimal charging and discharging for BES use in mitigating PV flicker. The method described herein is a deliberately conservative approach and the economic analysis shows that such an approach is likely not feasible. This is because the BESS has to "fill in" the worst-case days (realized as the design day), but is underutilized for much of the time. Alternative charging regimens can (theoretically) "do more with less."

5.4 Further Research

The most obvious avenue for further research is investigating the feasibility of implementing alternative discharge/recharge regimens. Investigation should seek to answer if the technology exists to implement such discharging/recharge regimens, how difficult it would be for electric utilities to implement these techniques, and if they would be economically feasible.

Another avenue for further research is to investigate the feasibility of implementing the battery lifetime prediction models mentioned in Section 2.3. The models were not used in this work because the models required more input about the nature of the battery systems used than what was available to this project. For the models to be useful to a project like this, one needs to have a good idea about the likely "boiler plate" parameters of the BESS are. One also needs to be able to simulate the discharging behavior of the BESS using solar data and power flow analysis, and use the simulation to inform the battery lifetime prediction model.

Reference Documents

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