THE VALUE OF GRID-SUPPORT PHOTOVOLTAICS IN PROVIDING DISTRIBUTION SYSTEM VOLTAGE SUPPORT

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ABSTRACT

Strategically sited grid-support photovoltaic (PV) applications have been proposed to provide distributed value (cost savings) to electric utilities experiencing transmission and distribution (T&D) system overloads. These applications can potentially defer capital upgrades, extend equipment maintenance intervals, reduce electrical line losses, and improve distribution system reliability. This research focuses on one aspect of the value of grid-support PV: the value to a substation transformer load tap changer. Results at Pacific Gas and Electric Company indicate that, due to the voltage support provided by the 0.50 MW PV plant at Kerman, California, the lifetime operation and maintenance costs of a transformer load tap changer at the Kerman Substation are reduced by $13,000. Although the method is generally applicable, the results are site specific.

1. INTRODUCTION

A common practice of electric utilities experiencing transmission and distribution (T&D) system overloads is to expand the substation, add lines, or upgrade equipment, all of which are capital intensive options. In 1988, it was hypothesized that strategically sited photovoltaics (PV) could benefit parts of T&D systems near or at overloaded conditions [1]. An evaluation methodology was developed and applied to a test case (Kerman Substation near Fresno, California). Results of this and other studies suggested that the value of PV to the T&D system could exceed its energy and generation capacity value [1, 2].

The importance of this finding indicated the need for empirical validation. This led to the construction of a 0.50 MW PV demonstration plant by Pacific Gas and Electric Company (PG&E) at Kerman, California as part of the PVUSA (PV for Utility Scale Applications) project. PVUSA is a national cooperative research and development effort under the auspices of the United States Department of Energy [3]. PVUSA developed guidelines of how to configure the plant to obtain the greatest total value [4] and designed a research test plan [5] to empirically determine the value of PV to the T&D and bulk generation systems. The Kerman PV plant, completed in June, 1993, is reported to be the world's first grid-support PV demonstration plant.

2. OBJECTIVE

Grid-support PV can provide many values to T&D systems. It can defer capital upgrades [6, 7], extend equipment maintenance intervals, reduce electrical line losses [8], and improve distribution system reliability, all with cost savings to utilities. This research examines the value of grid-support PV to a substation transformer load tap changer (LTC).

Utilities strive to maintain certain power quality standards throughout their service territories. One way they accomplish this is through the use of voltage regulation devices such as LTCs. Grid-support PV may provide value to an LTC by extending maintenance intervals and thus reducing maintenance costs. It achieves this by boosting voltage on the feeder which displaces some of the voltage regulation provided by the LTC.

This paper develops a method to quantify the level of feeder voltage support provided by a PV plant, the effect of this on LTC performance, and the corresponding economic value. The method is then applied to the 0.50 MW PVUSA PV plant located near PG&E's Kerman Substation.

3. METHODOLOGY

3.1 Voltage Support Provided by PV Plant

Voltage support (*VS*) provided by PV is the difference between voltage drop (ΔV) with and without the PV plant. Since voltage drop is the product of current and impedance, voltage drop without PV between a substation transformer and some location on a feeder equals

$$\Delta V = \int_0^x I(l)Z(l)dl \qquad (1)$$

where current (I) and impedance (Z) are functions of feeder location (l), 0 is the transformer location, and x is the location of interest on the feeder.

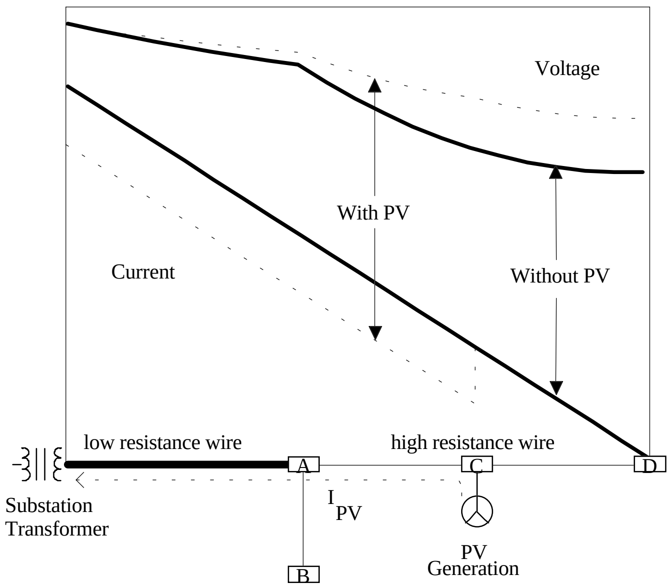

Fig. 1. Feeder voltage support provided by PV.

As illustrated in Fig. 1, a PV plant reduces voltage drop by reducing feeder current. Voltage support provided by a PV plant to point *B* on the lateral in Fig. 1 is the difference in voltage drop with and without PV. Voltage drop without PV is simply (1) with *B* substituted for *x*. Voltage drop with PV equals

$$\Delta V_B = \int_0^A \left[I(l) - I_{PV} \right] Z(l)dl + \int_A^B I(l)Z(l)dl \qquad (2)$$

which, since I_{PV} is constant over the line at any instant in time, equals

$$\Delta V_B = \int_0^B I(l)Z(l)dl - I_{PV}Z_A \qquad (3)$$

where Z_A is the total impedance from the substation transformer to point *A*.

Substituting *B* for *x* into (1) and subtracting (3), voltage support at point B is

$$VS_B = I_{PV}Z_A . \qquad (4)$$

A similar analysis will show that the voltage support at point *D* equals I_{PV} Z_C. Note that impedance in (4) can be replaced with resistance when the PV operates at unity power factor.

Equation (4) states that voltage support at any particular feeder location is the product of PV plant current and conductor impedance between the transformer and the point at which the lateral is attached to the line between the transformer and PV plant. The implications of this are: 1) voltage support is independent of feeder current; 2) voltage support is linearly related to plant output (and thus to plant size); and 3) voltage support anywhere on a feeder is known and is based only on PV plant output and feeder configuration.

3.2 Parameters Affecting LTC Operation

Translating voltage support to economic value requires understanding the relationship between LTC changes and feeder voltage requirements. LTC operation is based on voltage into the LTC, feeder voltage regulation devices on-line, LTC voltage range setting (this range is set to compensate for voltage drop on the feeder), and the variation in transformer load. This subsection outlines some of the most important parameters and how they relate to LTC changes.

Fig. 2 presents the relationship between desired substation voltage and the LTC voltage range setting and transformer load. The figure illustrates that desired substation voltage is a linear function of transformer load given an LTC voltage range setting. For illustration purposes, two settings are considered with the wide voltage range being twice the narrow voltage range. The LTC voltage range is set to narrow when small voltage drops are anticipated on the feeder; the range is set to wide when large voltage drops are anticipated. Many more settings are possible in practice.

Desired substation voltage as a function of load is converted to LTC changes by combining Fig. 2 with a load profile, such as the one presented in Fig. 3. The load axis is common to both figures so the resulting plot, Fig. 4, is desired substation voltage versus time. The top dashed curve corresponds to desired voltage for a wide voltage range and the bottom to a narrow voltage range.

Actual substation voltage for any given input voltage is limited by the number of available LTC taps and the voltage change produced by one LTC tap change (LTC step size). Thus, there is a difference between desired substation voltage (a continuous function) and actual substation voltage (a step function). When this difference exceeds the LTC bandwidth, the LTC changes taps.

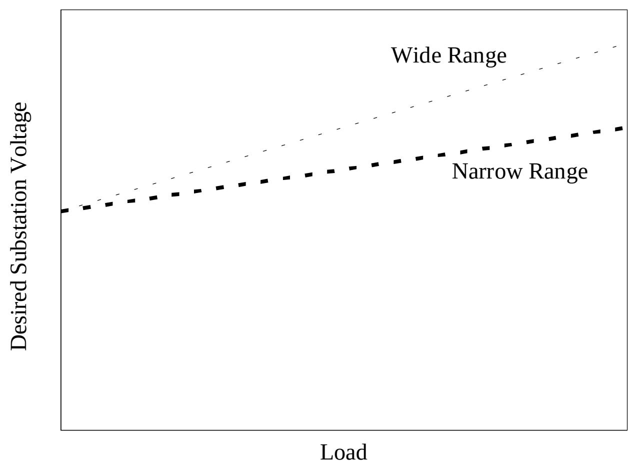

Fig. 2. Voltage versus load for two voltage range settings.

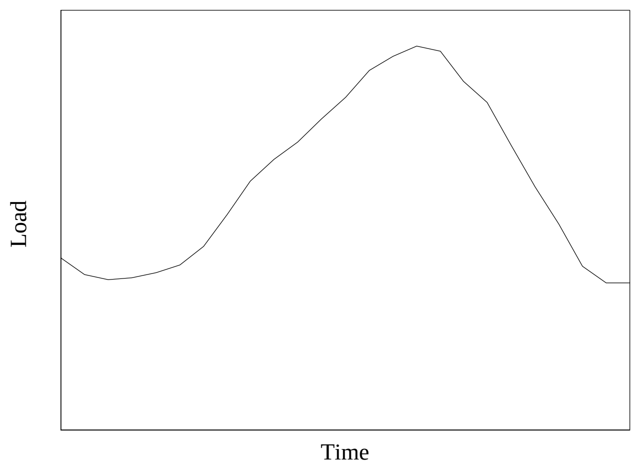

Fig. 3. Hypothetical load profile.

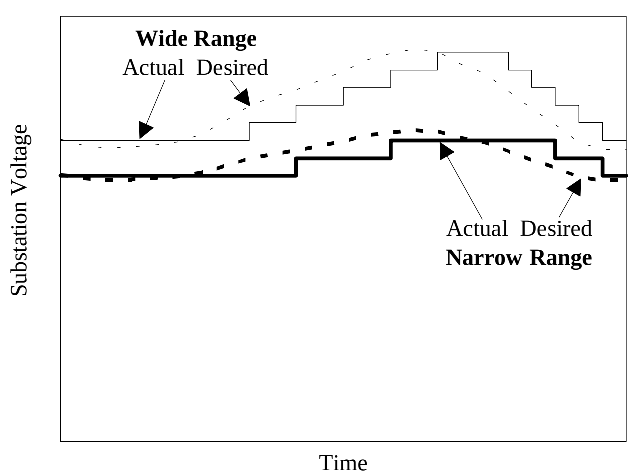

Fig. 4. Desired and actual voltages.

Fig. 4 plots actual substation voltage in addition to desired substation voltage. LTC bandwidth and LTC step size are the same for both cases; only the LTC voltage range setting is different. The figure suggests that, in general, there is a linear relationship between the number of LTC changes and voltage range setting when all other variables are constant. For example, the first four LTC changes for the wide voltage range correspond to two LTC changes for the narrow range. This is as expected since the narrow range was selected in Fig. 2 to be half the wide range.

Notice, however, that although there is an additional step up in the wide range case, there is no corresponding LTC change in the narrow range case. This is attributable to the fact that the LTC does not have a continuous range of voltages available. As the voltage range setting narrows, fractional LTC changes are eliminated. This is not important if actual loads follow the load pattern presented in Fig. 3.

In reality, however, load fluctuations occur throughout the day in addition to the overall daily load change. An LTC change occurs if these load fluctuations are large enough and the LTC voltage range is sufficiently wide; they stop occurring as the LTC voltage range narrows.

In order to make the results of this research broadly applicable, it is desirable to develop an equation that describes LTC changes as a function of voltage range setting. Following is one suggestion of what that equation might look like.

The discussion in the previous paragraphs suggests that one possible model is a combination of a linear and a non-linear equation where some fraction of the changes (F) are associated with the linear equation and the other (1-F) with the non-linear equation. If one assumes that the magnitude of the load fluctuations throughout the day have an exponential probability distribution, one non-linear equation that makes sense is an exponential function and the combination of the two equations becomes

$$C = C_{meas}\left[F\left(\frac{R - LTC_{step}}{R_{meas} - LTC_{step}}\right) + (1-F)e^{S(R-R_{meas})}\right] \quad (5)$$

where C is the number of LTC changes for an LTC voltage range setting of R, C_{meas} is the recorded number of LTC changes corresponding to an LTC voltage range setting of R_{meas}, LTC_{step} is the voltage change produced by one tap change, and S is a scaling factor that determines the slope of the exponential curve. Equation (5) is valid as long as R is greater than or equal to LTC_{step}.

Given LTC_{step} and a C_{meas} associated with some R_{meas}, F and S in (5) are needed before C is a function of only one variable, R. F, a unitless variable that describes what fraction of changes is attributable to the linear and non-linear terms in (5), is estimated by

$$F = \frac{365 \times 2 \times (L_{\max} - L_{\min})\Delta}{C_{meas} LTC_{step}} \tag{6}$$

where L_{max} minus L_{min} is the average daily load change (in MW/day), Δ is the desired voltage change per MW of load change (volts/MW), LTC_{step} is the voltage change produced by one tap change (volts/step), and C_{meas} is the recorded number of LTC changes in a year (steps/year). There are 365 days per year and the 2 accounts for the fact that if the LTC setting increases to meet the maximum load, it must decrease to meet the minimum load.

S, the scaling factor that determines the slope of the exponential curve, is estimated by inputting at least two sets of LTC changes under two sets of conditions into (5) and solving for S. Its value can be approximated if two sets of historical LTC data are unavailable.

3.3 Economic Value

The technical results from the previous subsections can be translated to economic value by computing the difference between the LTC maintenance cost with and without the PV plant. Specifically, one calculates the net present value of the maintenance cost with the PV plant and subtracts this from the net present value of the maintenance cost without the PV plant. The difference between the two is the value of PV to the transformer LTC.

The net present value (NPV) of a periodically recurring maintenance cost is a geometric series that reduces to

$$NPV = C\left[\frac{\left(\frac{1+r}{1+c}\right)^{MI} - \left(\frac{1+r}{1+c}\right)^{(N+1)MI}}{1-\left(\frac{1+r}{1+c}\right)^{MI}} + \left(\frac{SL}{MI} - N\right)\left(\frac{1+r}{1+c}\right)^{SL}\right] \tag{7}$$

where C is the current LTC maintenance procedure cost, r is the rate of inflation, c is the cost of capital, MI is the maintenance interval (it is expressed in years and equals the number of LTC changes between maintenance procedures divided by the annual number of LTC changes), N is the number of times the maintenance procedure is performed over the study life, and SL is the study life.

This expression is most familiar for annually recurring expenses, in which case MI equals 1, $(N+1)MI$ equals $SL+1$, and the second term in the brackets is zero [9]. Equation (7) includes the second term to account for times when the study life is not an integer multiple of the maintenance interval. In these cases, a fractional maintenance procedure must be performed at the end of the study life.

4. RESULTS

This section applies the method from the previous section to the 0.50 MW PV plant located near PG&E's Kerman Substation. The 0.50 MW plant is located on Feeder 1103, one of the two feeders regulated by the Kerman Bank 2 transformer LTC. Results, which are site specific, are based on measured data from this plant.

4.1 Voltage Support Provided by PV Plant

Field tests of Kerman Feeder 1103 were performed on July 1, 1993 and July 6, 1993 that facilitate quantification of the voltage support provided by the 0.50 MW PV plant. On July 6, a range of feeder load conditions, including extreme peak load conditions (6 MW, or 20 percent greater than normal peak loads), were simulated by having the distribution system operator transfer load from adjacent feeders to the Kerman Feeder 1103.

Fig. 5 presents the voltage support provided by the PV plant at the plant location as a function of plant current and feeder load. The figure suggests that voltage support is linearly related to PV plant current and is independent of feeder load. The Model line is constructed by multiplying plant current times feeder resistance as described in (4). The PV plant boosts feeder voltage at the plant by more than 2.5 volts at full plant output.

In addition to automatic measurements taken at the PV plant, feeder voltage was measured manually at three critical feeder locations. The distribution system operator took the PV plant off-line, field personnel measured three phase voltage, the distribution system operator put the plant back on-line, and field personnel remeasured the voltage. It took about 15 minutes between the first and last voltage measurements. Feeder current was not monitored at each location; rather, it was monitored every minute on only one phase at a location other than where the voltage measurements were taken.

Fig. 6 presents the voltage support provided by the PV plant as a function of the distance along the line between the PV plant and the transformer (i.e., the distance of the lateral is not included). The single line diagram in the figure is drawn to scale and shows where the voltage measurements were taken (they are marked with a box; manual measurements are marked with an M). Modeled values were calculated based on a plant output current of 20 Amps (0.4 MW), feeder resistance, and (4).

Although not a perfect relationship, the figure suggests that voltage support is independent of feeder load and that it is the point at which the lateral is connected to the line between the transformer and PV plant rather than the distance from the transformer that determines the level of voltage support. The less than ideal results may be explained by the long time delay (15 minutes) between measurements, the lack of current measurements at the locations of interest, and that the measurement instruments were disconnected between measurements.

The results in Figs. 5 and 6 are translated to feeder voltage support by examining voltage support at the feeder location with the lowest voltage; this location may change as PV plant size increases. Results are translated to voltage support on a group of feeders (and thus to the LTC since it serves two feeders) by examining minimum voltage on all feeders served. Minimum voltage location on adjacent feeders, however, does not change since PV plant voltage support to adjacent feeders is zero.

Fig. 5 implies that, since voltage support is linearly related to PV plant output, it is also linearly related to PV plant size for plants operating at a given percentage of their rating. Thus, calculating minimum voltages with the PV plant on-line requires knowing what the voltages were with the PV plant off-line and the voltage increases per unit of PV.

Minimum voltages with the PV plant off-line during the July 6, 1993 test were 118.9 volts, 116.6 volts, and 118.5 volts at the manual measurement locations M1, M2, and M3 in Fig. 6. Fig. 7 presents minimum voltage on the group of feeders that the LTC serves as a function of PV plant size (dark solid line) by combining these initial voltages with the voltage support provided by a PV plant operating at 80 percent of its rating; minimum feeder voltage on an adjacent feeder (labeled adjacent feeder) is assumed to be 120.5 volts. The figure suggests that a plant rated at 0.50 MW boosts voltage by about 2 volts at the location with the lowest minimum voltage.

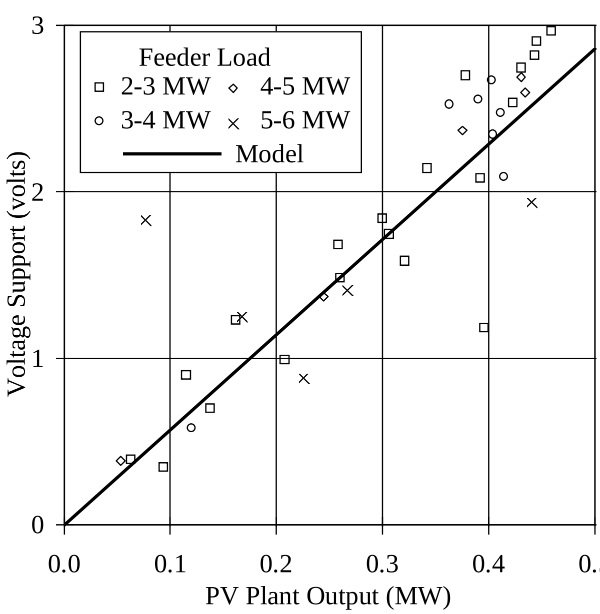

Fig. 5. Voltage support versus PV plant output at various feeder load levels (July 1, 1993 and July 6, 1993).

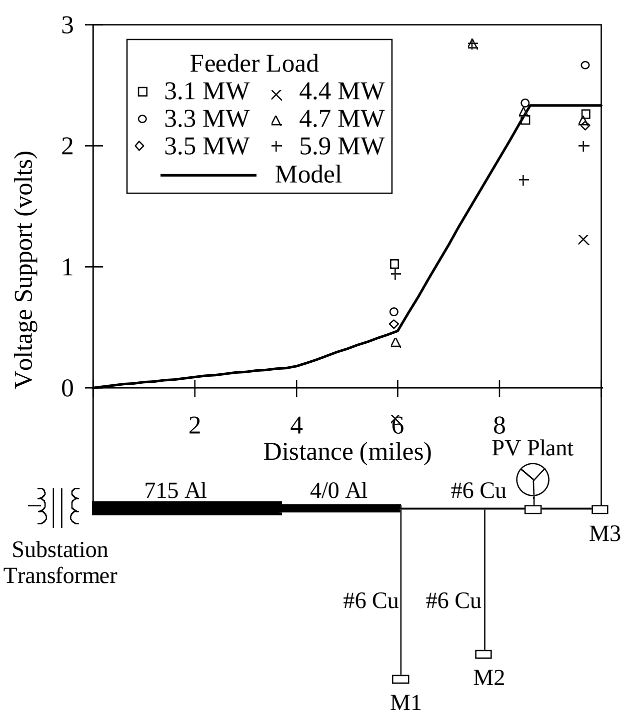

Fig. 6. Voltage support provided by PV plant at 0.40 MW output at various locations (July 6, 1993).

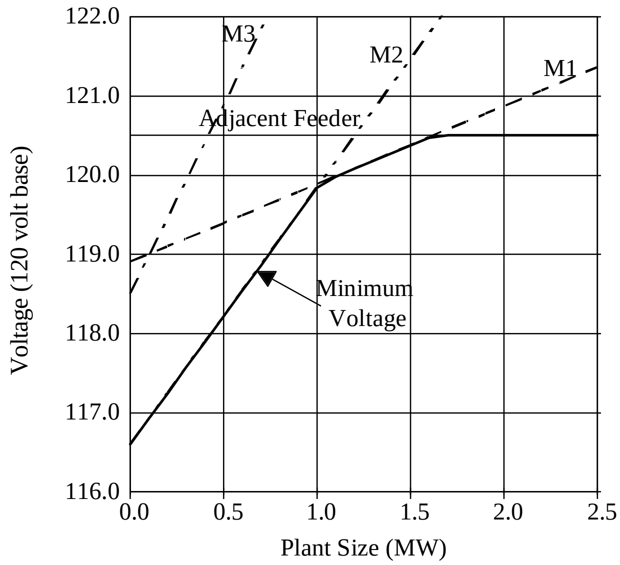

Fig. 7. Voltage support versus PV plant size.

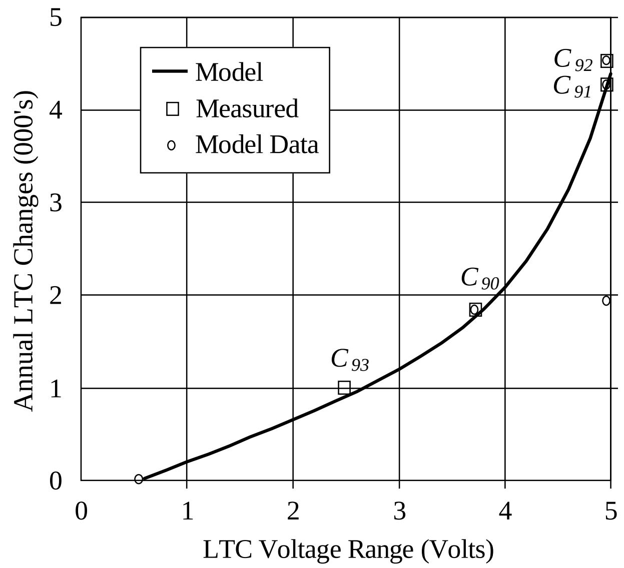

Fig. 8. Annual LTC changes versus voltage range setting.

4.2 LTC Changes and LTC Voltage Range Setting

The relationship between LTC changes and voltage support must be understood to translate PV voltage support to a reduction in LTC changes. The squares in Fig. 8 represent the measured number of LTC changes for 1990 through 1993. All points represent a year's worth of data except 1993, which is based on 40 percent of the year and scaled to an annual estimate.

Fig. 8 includes model results. The data used to construct the model are denoted by the circles. As described in (5), the model is based on the recorded number of LTC changes (C_{meas}) corresponding to a given LTC voltage range setting (R_{meas}), the voltage change produced by one tap change (LTC_{step}), the fraction of load changes associated with daily load changes (F), and the scaling factor that determines the slope of the exponential curve (S). Although the LTC bandwidth changed slightly between years (±0.75 volts in 1990 and 1993, and ±0.65 volts in 1991 and 1992), this change is ignored.

C_{meas} associated with an R_{meas} of 5.0 volts equals 4,400 LTC changes per year (i.e., the average of LTC changes in 1991 and 1992); LTC_{step} equals 9/16 volt; F equals 0.44, and is calculated using (6) and estimates of the average daily load change (L_{max}-L_{min}) of 3.06 MW/day and Δ of 0.5 volt/MW (i.e., voltage range of 5 volts divided by maximum transformer load of 10 MW); and S equals 1.43, and is determined by solving for S in (5) and then inputting 1990 and 1992 conditions. The figure suggests that the model is a good fit to measured data.

4.3 Economic Value

Economic value can be calculated now that the voltage support provided by the PV plant and the relationship between LTC voltage range setting and annual LTC changes are known. As described earlier, the economic value of a PV plant to the LTC is the difference between the LTC maintenance cost without the PV plant and the maintenance cost with the PV plant.

The LTC is routinely inspected every four to six years. During the inspection, worn parts are replaced. At the Kerman Substation, it is estimated that the variable maintenance cost (C) associated with parts replacement is \$15,000 and occurs every 50,000 LTC changes. According to Fig. 8, the current LTC setting corresponds to 4,400 changes per year. This translates to a maintenance interval (MI) of 11.4 years. Using (7) and the assumptions that inflation (r) is 5.0 percent, cost of capital (c) is 10.0 percent, and the study life (SL) equals the PV plant life of 30 years, the net present value of the LTC maintenance cost over 30 years without PV is \$16,400.

According to Fig. 8, a new LTC voltage range setting of 2.5 volts corresponds to about 1,000 changes per year. This translates to a maintenance interval of about 50 years. Using the same assumptions as above and (7), the net present value of LTC maintenance cost over 30 years with a 0.5 MW PV plant is about \$3,400. Thus, the value of PV to the LTC is the difference between the original cost (\$16,400) and the new cost (\$3,400) or \$13,000. Fig. 9 presents this same calculation for a range of PV plant sizes.

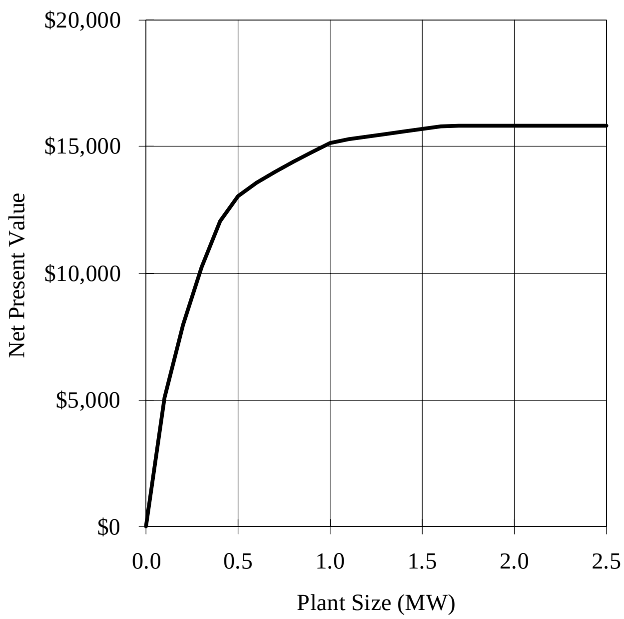

Fig. 9. LTC value versus PV plant size.

5. CONCLUSIONS AND FUTURE RESEARCH

A simple method was developed in this paper to estimate the value of grid-support PV to a substation transformer LTC. The hypothesis was that PV reduces LTC maintenance costs because LTC changes are a function of feeder voltage support requirements and a PV plant reduces these requirements by providing feeder voltage support. This voltage support translates to a reduced LTC voltage range setting. Results suggest that the 0.50 MW PV plant near the Kerman Substation will save $13,000 (NPV) in LTC maintenance costs over the 30 year life of the plant.

Important observations resulting from this work are: 1) voltage support provided by a PV plant (or any other form of distributed generation) is independent of feeder current; 2) voltage support is linearly related to plant output (and thus to plant size); and 3) voltage support anywhere on a feeder is known and is based only on plant output and feeder configuration.

Future research needs can be divided into economic and technical categories. From an economic perspective, the possible prevention of LTC failure, and thus the deferment of a capital expenditure, has not been considered. This value might exceed the maintenance savings estimated in this paper. In addition, more research is needed to assess the relationship between the number of LTC changes and maintenance costs. An examination of historical cost data would be beneficial. From a technical perspective, the model relating the LTC voltage range setting to LTC changes needs further evaluation. A specific area of concern is the omission of transmission voltage in the model.

6. ACKNOWLEDGMENTS

It was through the efforts of PG&E and other PVUSA members that the 0.50 MW Kerman PV plant was constructed so this analysis could be performed. Joaquin Buendia of PG&E's Fresno Division prompted initial formulation of the hypothesis and demonstrated unending patience in answering all the questions necessary to perform the analysis. Valuable comments were received from Ken Lau, Jimmie Yee, John Monastario, and John Martin of PG&E, and George Tennyson of the Department of Energy. Sam Dooms of Utility Distribution Electric obtained data crucial to this analysis. Jim Augustyn and Rob Nelson of Augustyn + Company performed special data collection tests. John Weyant of Stanford University provided enthusiastic support and interest in this work.

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