THE VALUE OF GRID-SUPPORT PHOTOVOLTAICS TO SUBSTATION TRANSFORMERS

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***Abstract* — Strategically sited grid-support photovoltaic (PV) applications have been proposed to provide value (cost savings) to electric utilities experiencing transmission and distribution (T&D) system overloads. These applications can potentially defer transformer and transmission line upgrades, extend equipment maintenance intervals, reduce electrical line losses, and improve distribution system reliability. This paper calculates the economic value of strategically placed grid-support PV to a substation transformer. Results at Pacific Gas and Electric Company indicate that the 0.50 MW PV plant in Kerman, California can defer a transformer upgrade for 4.6 years for a value of $398,000. These results are site specific.**

I. INTRODUCTION

The standard practice of electric utilities experiencing transmission and distribution (T&D) system overloads is to upgrade equipment. In 1988, it was hypothesized that strategically sited photovoltaics (PV) could benefit overloaded parts of the T&D system [1]. An evaluation methodology was developed and applied to a test case (Kerman Substation near Fresno, California). Simulated data suggested that value of PV to the T&D system could exceed its value to the bulk generation system [1].

The importance of this finding indicated the need for empirical validation. This led to a 0.50 MW PV demonstration project at Kerman, California as part of project PVUSA (PV for Utility Scale Applications). PVUSA is a national cooperative research and development effort under the auspices of the United States Department of Energy.

PVUSA developed plant specifications [2] and designed a research test plan [3] to 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 first grid-support PV demonstration in the world.

Grid-support PV can provide many values to T&D systems. It can defer transformer and transmission line upgrades, extend equipment maintenance intervals, reduce electrical line losses, and improve distribution system reliability, all with cost savings to utilities.

This paper focuses on the economic value of strategically placed grid-support PV to substation transformers. It calculates the transformer upgrade deferral value for the Kerman Substation using the following approach. Reduction in the transformer's hottest-spot temperature is determined using an IEEE transformer temperature model and measured transformer and PV plant data on the 1993 peak load day. The temperature reduction is converted to allowable load increase and then to years of deferral using annual load growth estimates. Value is a function of years of deferral and other economic parameters.

II. APPROACH

Grid-support PV defers a substation transformer upgrade by supplying power on the low voltage side of a transformer during peak usage. The reduced transformer load results in decreased transformer temperatures and longer life. A cooler transformer can accommodate additional load growth and enable the utility to defer purchase of a new transformer until fully needed.

The number of years of deferral can be calculated by determining the PV plant's reduction in peak load and dividing by projected annual load growth. This approach, however, fails to account for the fact that peak load is not the only factor affecting transformer temperature.

Fortunately, much is known about transformer performance [4, 5]. The IEEE has even developed a detailed model (called the IEEE model in this paper) for loading power transformers [6]. The guide to the model bases its transformer loading recommendations on the degradation effects of temperature and time on winding

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insulation deterioration. It assumes an exponential relationship between transformer life and the transformer's highest, or hottest-spot, temperature.

The guide acknowledges that it is very difficult to accurately predict the cumulative effects of temperature and time on winding insulation deterioration [6]. This makes it problematic to convert hottest-spot temperature reduction provided by a PV plant to transformer life extension.

Some utilities (such as Pacific Gas and Electric Company) use the IEEE model as a decision tool to determine when a transformer upgrade is needed based on a transformer's hottest-spot temperature rather than transformer loss of life. This paper extends that practice to calculate allowable load increase. It uses the IEEE model to compute transformer hottest-spot temperature for transformer load with no PV. This calculation is repeated for transformer load increased by some percentage minus PV plant output. Allowable load increase is the percentage increase in load that results in the two scenarios having the same maximum hottest-spot temperature.

Allowable load increase is converted to years of deferral using annual load growth estimates. Upgrade deferral value is a function of years of deferral and other economic parameters.

III. BACKGROUND

The approach described in the previous section requires transformer hottest-spot temperature estimates. Fortunately, much work has been invested in developing a model to estimate hottest-spot temperature [6]. Some have used the IEEE model to evaluate hottest-spot temperature reduction provided by PV [1, 2, 7]. Slight changes need to be made in the model, however, since it was intended to use average ambient temperature under peak load conditions while this research uses measured ambient temperature under a range of conditions. This section describes the model and inaccuracies that might occur when using the model in such a manner.

The IEEE model suggests that hottest-spot winding temperature (θ_{hs}) is the summation of ambient temperature (θ_a), top-oil temperature rise over ambient temperature (θ_o), and hottest-spot conductor temperature rise over top-oil temperature (θ_g):

$$\theta_{hs} = \theta_a + \theta_o + \theta_g \,. \tag{1}$$

Top-oil temperature rise (θ_o) is a function of ultimate top-oil temperature rise over ambient temperature (θ_u), initial top-oil temperature rise over ambient temperature (θ_i), elapsed time (*t*), and the thermal time constant (τ_0). Hottest-spot conductor temperature rise (θ_g) is a function of the ratio of load to rated load (*K*), hottest-spot conductor temperature rise over top-oil temperature at rated load [$\theta_g(fl)$], and a term *m*, which accounts for the effect of variations in the hot spot gradient due to changes in loading.

$$\theta_o = \left(\theta_u - \theta_i\right)\left(1 - e^{\left(-t/\tau_0\right)}\right) + \theta_i \tag{2}$$

$$\theta_g = \theta_g(fl) K^{2m} \tag{3}$$

The ultimate top-oil temperature rise over ambient temperature and thermal time constant in (2) are:

$$\theta_u = \theta_{fl}\left(\frac{K^2 R + 1}{R + 1}\right)^n \tag{4}$$

$$\tau_0 = \tau_r \frac{\left(\dfrac{\theta_u}{\theta_{fl}}\right) - \left(\dfrac{\theta_i}{\theta_{fl}}\right)}{\left(\dfrac{\theta_u}{\theta_{fl}}\right)^{1/n} - \left(\dfrac{\theta_i}{\theta_{fl}}\right)^{1/n}} \tag{5}$$

$$\tau_r = \left(C\theta_{fl} / P_{fl}\right) \tag{6}$$

where θ_{fl} is the top-oil temperature rise over ambient temperature at rated load, *R* is the ratio of load loss at rated load to no load loss, τ_r is the thermal time constant at rated load, *C* is the transformer's thermal capacity, P_{fl} is the total power loss, and *n* is the exponential power of total loss versus top-oil temperature rise. *n* affects the magnitude of the ultimate top-oil temperature rise and *C* affects the rate of top-oil temperature change.

Research performed for this paper suggests that caution is needed when using measured ambient temperature in the IEEE model. As shown in (1), ambient temperature directly affects hottest-spot temperature. Unlike top-oil temperature rise, no time lag is associated with a change in ambient temperature. This is not a problem when using average ambient temperature but may result in errors if ambient temperature varies. Ambient temperature varies daily by more than 25 °C in the field.

IV. RESULTS AND DISCUSSION

A. Modification of IEEE Model

Transformer top-oil temperature has been continuously monitored at the Kerman Substation since 1991 using temperature probes. These probes have an absolute accuracy of +/- 1.5 °C at 100 °C. The thirty-year old transformer at the Kerman Substation is an OA/FA (65/65 °C) 8400/10500

KVA transformer. No load losses are 14.421 kW and total losses at the OA rating are 61.965 kW. This translates to total losses at the FA rating of 74.287 kW. The average winding rise over top-oil temperature and top-oil rise over ambient temperature are 60.7 °C and 49.2 °C at the OA rating and 60.6 °C and 43.0 °C at the FA rating. The core and coils weigh 24,800 lbs, the tank weighs 17,965 lbs, and there are 3,177 gallons of oil in the tank.

As described in the previous section, hottest-spot temperature is needed for the analysis. The measurements at the Kerman Substation, however, include only top-oil temperature. Thus, evaluation of the IEEE model is based on the comparison of measured and simulated top-oil temperatures. The IEEE model's calculation of hottest-spot temperature rise over top-oil temperature is assumed to be correct because there was no way to verify it.

Fig. 1 presents simulated top-oil temperature using the IEEE model (light dashed line) as presented in [6] and measured transformer temperature (dark solid line) for the Kerman Substation on the 1993 peak day. Simulated top-oil temperature is the sum of ambient temperature plus top-oil temperature rise over ambient temperature.

Data (presented in Table 1) were collected as follows. Load, top-oil temperature, and fan status were monitored at the substation transformer every 5 seconds and half-hour averages stored for analysis. The fan started at 12:23 and stopped at 23:43. Ambient temperature was measured 8 miles away from the transformer at the PV plant every 5 seconds and half-hour averages stored for analysis.

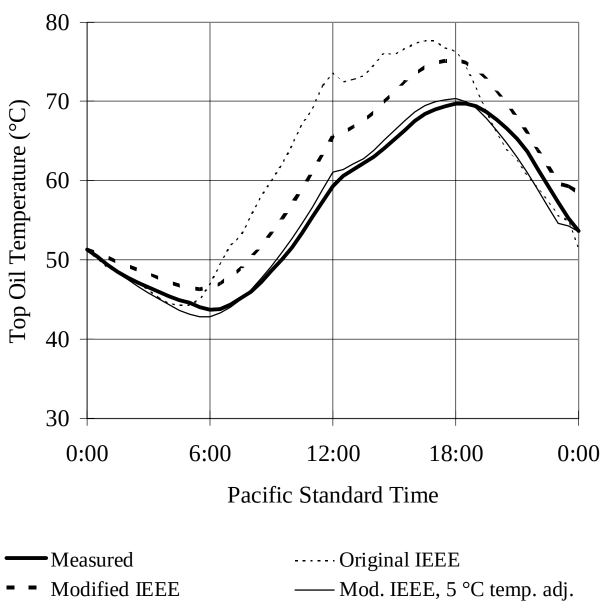

Fig. 1. Accuracy of top-oil temperature simulations (June 25, 1993).

Fig. 1 shows that the Original IEEE curve is shifted several hours earlier than the measured curve. As shown by the Modified IEEE curve (dark dashed line) the IEEE model's accuracy is improved by including a time lag in the effect of ambient temperature on top-oil temperature. This is accomplished by moving ambient temperature from the hottest-spot equation (1) to the ultimate top-oil temperature equation (4). Modified equations are:

$$\theta_{hs} = \theta_o' + \theta_g \tag{1a}$$

$$\theta_u' = \theta_{fl}\left(\frac{K^2 R + 1}{R + 1}\right)^n + \theta_a . \tag{4a}$$

All top-oil temperatures (θ_o', θ_i', and θ_u') are now in units of *absolute* top-oil temperature rather than top-oil temperature *rise* over ambient temperature. The time constant, τ_0, however, is still based on θ_u and θ_i rather than θ_u' and θ_i'.

As seen in Fig. 1, although the shape of the modified IEEE and measured temperature curves are the same, there is still a magnitude error. One possible way to explain this error is that the ambient temperature measured at the PV plant, which is 8 miles away, is different than that seen by the substation transformer. There is a much better match to the data if it is assumed that the ambient temperature at the substation is 5 °C lower than the ambient temperature at the PV plant (light solid line).

Table 1. Load, ambient temperature, measured top-oil temperature, and cooling fan status (June 25, 1993).

Time	Load (MVA)	Ambient (°C)	Top-oil (°C)	Fan Status	Time	Load (MVA)	Ambient (°C)	Top-oil (°C)	Fan Status
0:00	4.09	23.9	51.3	Off	12:00	7.93	38.5	59.3	Off
0:30	3.81	23.2	50.4	Off	12:30	8.24	38.1	60.6	On
1:00	3.71	22.5	49.4	Off	13:00	8.57	38.8	61.4	On
1:30	3.64	22.3	48.5	Off	13:30	8.59	39.5	62.2	On
2:00	3.59	22.1	47.8	Off	14:00	8.83	41.0	63.0	On
2:30	3.62	21.8	47.1	Off	14:30	9.09	42.3	64.0	On
3:00	3.62	21.0	46.6	Off	15:00	9.28	41.8	65.2	On
3:30	3.69	20.3	46.0	Off	15:30	9.47	42.1	66.4	On
4:00	3.74	19.7	45.4	Off	16:00	9.53	42.3	67.5	On
4:30	3.79	19.7	44.9	Off	16:30	9.31	42.5	68.5	On
5:00	3.92	19.8	44.6	Off	17:00	9.12	42.5	69.0	On
5:30	4.13	20.5	44.1	Off	17:30	9.17	41.6	69.4	On
6:00	4.38	22.4	43.7	Off	18:00	9.03	41.3	69.7	On
6:30	4.84	24.6	43.8	Off	18:30	8.84	39.6	69.7	On
7:00	5.14	26.5	44.4	Off	19:00	8.65	37.3	69.4	On
7:30	5.58	27.1	45.1	Off	19:30	8.46	34.7	68.7	On
8:00	5.93	28.9	46.0	Off	20:00	8.31	32.6	67.7	On
8:30	6.15	30.6	47.2	Off	20:30	8.21	30.9	66.6	On
9:00	6.44	31.6	48.6	Off	21:00	7.85	30.4	65.3	On
9:30	6.70	32.7	50.0	Off	21:30	7.35	29.3	63.6	On
10:00	6.87	34.1	51.6	Off	22:00	6.81	29.1	61.5	On
10:30	7.19	35.8	53.4	Off	22:30	6.32	28.7	59.4	On
11:00	7.41	36.5	55.4	Off	23:00	5.89	28.2	57.3	On
11:30	7.71	38.2	57.4	Off	23:30	5.09	27.5	55.3	Off

B. Modified Model Accuracy

Table 2 compares the accuracy of the original and modified IEEE models using ten peak days in 1992 and five peak days in 1993. Results indicate that the modified IEEE model more accurately predicts top-oil temperatures for the Kerman Substation transformer and suggest more accuracy for transformers under field conditions in general. In addition, a 5 °C ambient temperature adjustment (this adjustment is not recommended in general) improves model accuracy. Note that results in the following section are essentially unaffected by the 5 °C adjustment since the analysis is based on relative temperature comparisons and the adjustment addresses a scaling problem. Failing to use the modified model, however, can result in substantial error.

Table 2. Root mean square error analysis on 15 peak days.

	Original IEEE	Modified IEEE
No ambient temp. adjustment	8.2 °C	5.1 °C
5 °C ambient temp. adjustment	6.1 °C	1.9 °C

C. Allowable Load Increase Provided by PV

The modified model can be used to evaluate the allowable load increase provided by the PV. The following four figures present two allowable load increase analyses using the 1993 peak day (June 25, 1993). In all figures, transformer load without PV is the dark solid line, transformer load with load increase is the light dashed line, and transformer load with load increase minus PV plant output is the light solid line. Figs. 2 and 3 use measured PV output data from the 0.5 MW PV plant while Figs. 4 and 5 scale measured output by a factor of 10 to a plant size of 5.0 MW. Transformer and feeder losses are taken into account in the analysis.

The analysis is performed as follows. The initial transformer load in Fig. 2 (dark solid line) is increased by some percentage throughout the day (light dashed line) and then decreased by PV plant output (light solid line). The allowable load increase percentage is selected such that the maximum hottest-spot temperature in Fig. 3 is the same without PV (dark solid line) as with increase and PV (light solid line). The figures suggest that the PV plant reduced the maximum hottest-spot temperature by 4 °C, half of which came from a lower top-oil temperature due to a decrease in load throughout the day. The allowable load increase is 4.6 percent or 0.46 MW at the peak.

Figs. 4 and 5 repeat the analysis for a 5.0 MW PV plant. The allowable load increase is 22.9 percent or 2.29 MW at the peak. Notice that in this case, the new peak load occurs later in the day and is larger than the original peak load.

Fig. 6 presents the allowable load increase as a function of PV plant size. For comparison purposes, results using the original IEEE model and a load reduction approach are included. The figure indicates that all results are similar at small PV plant sizes. At larger sizes, however, the original IEEE model overestimates and the load reduction method underestimates the allowable load increase. The original IEEE model overestimates because it models the transformer

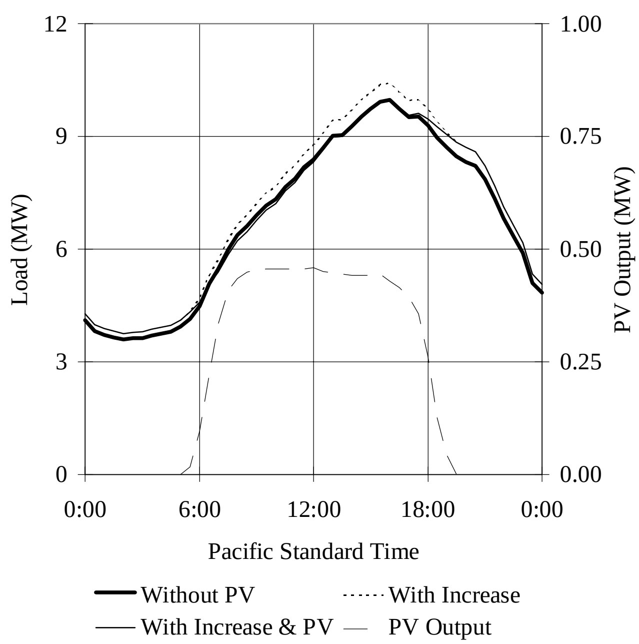

Fig. 2. Transformer load without PV, with 4.6% load increase, and with 4.6% load increase and 0.5 MW PV on peak day (June 25, 1993).

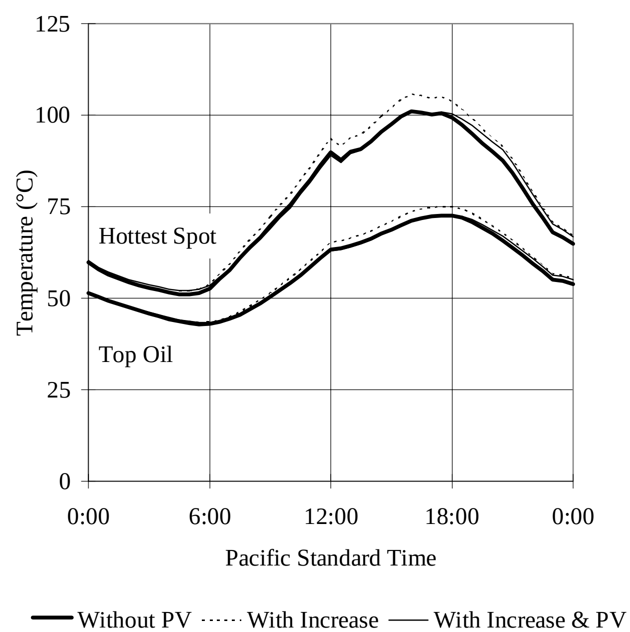

Fig. 3. Transformer temperatures without PV, with 4.6% load increase, and with 4.6% load increase and 0.5 MW PV on peak day (June 25, 1993).

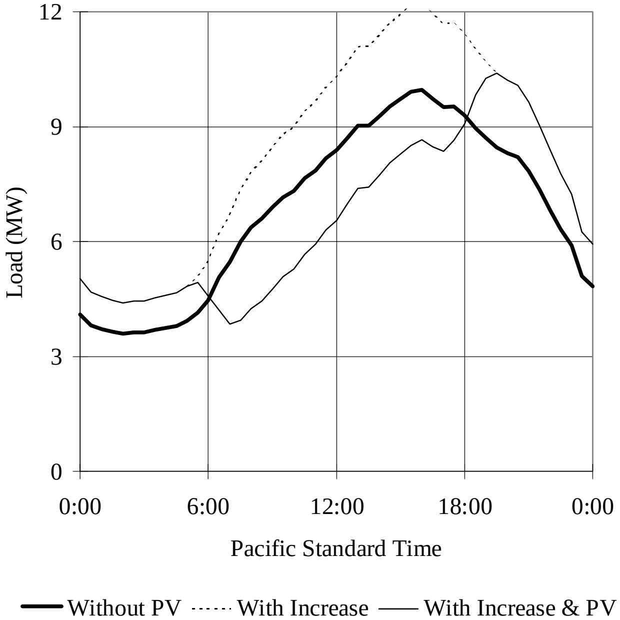

Fig. 4. Transformer load without PV, with 22.9% load increase, and with 22.9% load increase and 5.0 MW PV on peak day (June 25, 1993).

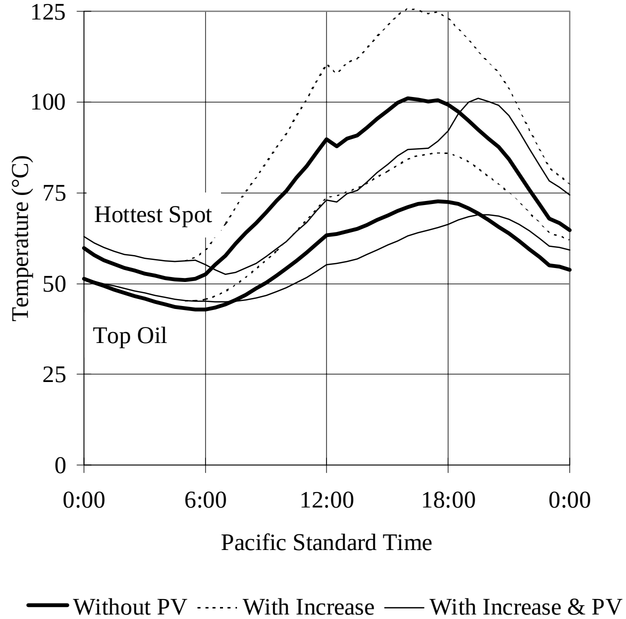

Fig. 5. Transformer temperatures without PV, with 22.9% load increase, and with 22.9% load increase and 5.0 MW PV on peak day (June 25, 1993).

peak temperature as occurring earlier in the day than it actually does. The load reduction method underestimates because, as Figs. 4 and 5 show, even as the peak shifts to times when the PV is not operating, PV output earlier in the day cools the transformer's oil. Errors on the order of 30 percent are seen in Fig. 6.

V. Estimated Transformer Deferral Value

This section converts the allowable load increase from the previous section into the value of grid-support PV to the substation transformer in two steps. First, the allowable load increase is translated to number of years of deferral. Second, years of deferral is combined with economic parameters to calculate value.

The number of years of deferral (n_d) equals the allowable load increase divided by the annual load growth:

$$n_d = \frac{\text{allowable load increase}}{\text{annual load growth}}. \tag{7}$$

Value of grid-support PV to the substation transformer, in net present value (NPV) terms, equals:

$$\text{Value} = C(1+C\text{SC})\left\{\left[1-\left(\frac{1+r}{1+c}\right)^{n_d}\right]+S\left[\frac{n_d}{life}\left(\frac{1+r}{1+c}\right)^{life}\right]\right\} \tag{8}$$

The terms outside the curly brackets equal the upgrade cost adjusted for capital specific costs such as taxes, insurance and other costs. Deferral value equals the first term in the curly brackets times this value; salvage value of the new transformer at the end of the study period equals the second term in the curly brackets times this value. It is estimated that upgrade cost (*C*) is $1,050,000, capital specific costs (*CSC*) are 33 percent, inflation (*r*) is 2.5 percent, cost of capital (*c*) is 10 percent, percent of investment that can be salvaged (*S*) is 50 percent, and transformer life (*life*) is 30 years.

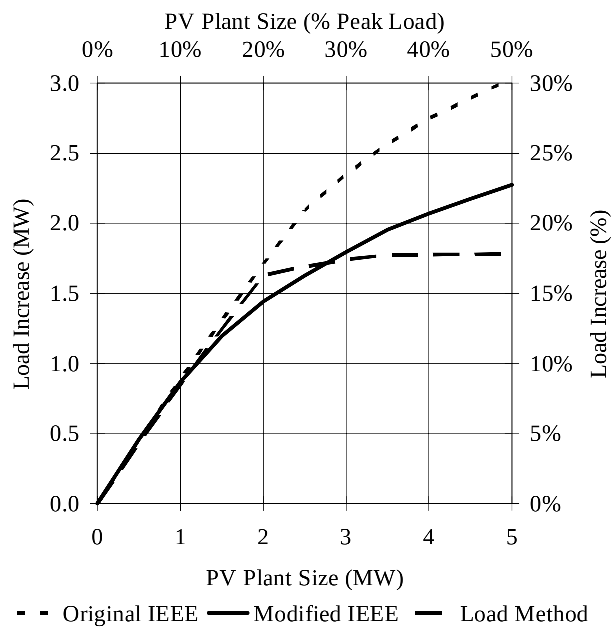

Fig. 6. Allowable load increase versus PV plant size.

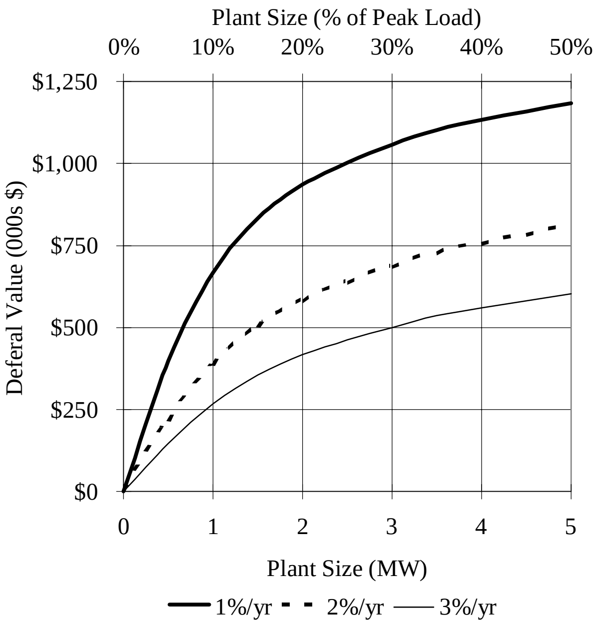

Fig. 7. Total deferral value (NPV) for three load growth scenarios.

Fig. 7 describes the transformer upgrade deferral value for three different rates of load growth. The figure suggests that the value of the 0.50 MW Kerman PV plant is estimated to be $398,000. This assumes that all available load transfers have been made, the transformer would have been replaced immediately if the PV had not been added, and that annual load growth was 1 percent.

VI. CONCLUSIONS AND FUTURE RESEARCH

This paper has attempted to identify and delineate one of the several cost-saving components of grid-support PV. It has demonstrated that strategically sited grid-support PV provides value to substation transformers. It showed that a 0.50 MW PV plant reduced the Kerman Substation transformer's hottest-spot temperature by 4 °C on a peak day in 1993. This converted to an allowable load increase of 4.6 percent or 0.46 MW on peak and a transformer upgrade deferral value of $398,000, assuming that the transformer needed upgrading and there was an annual load growth of 1 percent. It should be noted that the correlation between value and PV plant size is non-linear: for example, tripling plant size only doubles the value. Future work is needed to replicate model runs with a seasonal perspective and a multiple year data set. In addition, work is needed to deal with uncertainties in load growth, escalation rate, and cost of capital from an economic perspective.

VII. BIOGRAPHIES

Tom Hoff has a BS from California Lutheran College, Thousand Oaks, California, an MS from Washington University, St. Louis, Missouri, an MDiv from Trinity Evangelical Divinity School, and is pursuing a Ph.D. at Stanford University, Stanford, California. Mr. Hoff has equipped utilities with tools to value PV and other renewable technologies. His research includes developing methods to calculate the energy and generation capacity value of non-dispatchable resources, investigating PV as a demand side management option, and analyzing distributed generation and storage technologies.

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