Understanding factors that influence the risk of a cascade of outages due to inverter disconnection

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***Abstract*—Because of the rapid growth in distributed solar generation, there is growing concern that inverter-connected generators, which are designed to automatically disconnect under abnormal voltage conditions, could disconnect in a manner that would lead to a cascade of outages and ultimately instability or voltage collapse. This paper studies the conditions under which a cascading inverter collapse of this sort could occur. More specifically, we identify engineering design parameters, such as time constants, that influence the speed and nature of these cascades. While this model is preliminary, the results suggest that risk increases with a number of factors including: large transmission or distribution line impedances, a large variance in inverter voltage setpoints, and an inappropriate number of inverter-based resources that can contribute to supplying too much or not enough power.**

***Index Terms*—Cascade of outages, disconnection, inverters, renewable generation, risk factors**

I. Notation

Name	Symbol	Unit
Number of inverters	N	-
Load	P_d	MW
Line resistance	R	p.u.
Line reactance	X	p.u.
Nominal Voltage	V_0	p.u.
Acc. voltage, low	V_L	p.u.
Acc. voltage, high	V_H	p.u.
New voltage	V_i, t	p.u.
New area	A_n	voltseconds
Maximum area	$A_{\max}$	voltseconds
σ on max area	σ_A	voltseconds
Time step	dt	seconds
Simulation time	t_s	sec
Time of fault	t_f	sec

II. Introduction

Inverters are an integral part of all solar photovoltaic (PV) generation systems. As distributed PV generation forms an increasingly large fraction of the power supply portfolio, the discrete and continuous dynamics of inverters become increasingly critical to power system reliability, security and resilience. As of June 2019, 67 GW of PV capacity had been installed in the U.S., and the capacity installed per year is predicted to double over the next 5 years [1].

This work was supported in part by US NSF Awards ECCS-1254549 and CNS-1735513.

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Renewable energy has a number of important benefits in terms of mitigating air emissions from fossil fuel power plants; thus, removing barriers or challenges to incorporating renewable distributed energy resources is important. One potential barrier to PV adoption is the growing concern among industry professionals about the potential for cascading grid failures due to unexpected inverter disconnections. As specified in IEEE Standard 1547 [2], inverters are typically designed to disconnect when exposed to abnormal voltage or frequency conditions. While these rules are important to protect equipment and to ensure safety, inverter disconnection rules change the discrete dynamics of a power system and have the potential to trigger cascading failures.

Cascading failures and the blackouts that can result are not new to the electricity industry. One of the most infamous examples is the August 2003 blackout in the Northeast United States and Southern Canada, which was triggered by a number of events, including power lines contacting overgrown trees [3]. Many steps have been taken to protect against cascading blackouts [4], [5], such as improved reliability standards and additional oversight by NERC. Given that inverter-connected power plants make up an increasingly large fraction of the power supply portfolio there is need for tools that help us to better understand the potential cascading failure risk associated with this new generation.

There is substantial industry concern about the potential for cascading inverter failures. Analyses of a number of previous power system disturbances suggest that inverter disconnections can lead to loss of generation. For example, inverter outages triggered a cascading failure in Australia in 2016 [6].

There is a growing and valuable literature on the impact of PV generation on power systems reliability and stability. Some have found that inverter output voltage is sensitive to sudden change [7]. Others argue that remote monitoring and fault detection of PV systems is necessary because in some cases faulty components will not accurately sense the conditions and disconnect [8], which is related to to the lifetime of PV-to grid inverters [9] and the components that make up inverters [10]. Another factor that is important to PV inverter performance under voltage fluctuations is influence from grid-fault controllers and control strategies based on using continuous values for control parameters [11]. To increase stability of systems with a significant amount of distributed energy resources (DERS), solar power output can be adjusted to respond to changes in voltage [12]. Additionally, fault response analysis of such systems can be conducted by updating conventional analytical network analysis techniques [13]. Though PV systems can seem fragile, there are indications that PV systems can withstand natural disasters and function after the event [14].

In this paper, we will focus specifically on identifying parameters that could increase the risk of inverter-caused cascading failure, and more specifically determine the range of values that could impact blackout risk. We will do this using a new simulation model called the Time-Dependant Inverters Model (TiDIM), which is able to identify factors that contribute to voltage collapse.

III. Methods

Inverter disconnections change power system dynamics because each inverter is supplying a certain amount of power to the system, and when an inverter disconnects, it is no longer contributes to the total (active or reactive) power generated. As a result, generation and load are no longer balanced, leading to changes in both frequency and voltage.

IEEE 1547 makes recommendations for when an inverter should disconnect due to off-nominal voltage conditions. Per IEEE 1547, there is a non-zero time delay between when an abnormality is detected and when the disconnection occurs, which is known as fault ride through time. The time delays specified in 1547-2003 are summarized in Table I. This paper uses these time delays to represent the fact that most existing inverters were designed to meet the 2003 standard. The default settings specified in 1547-2018 are similar, but the inverter settings can be adjusted to allowable ride through times upwards of 20 seconds for some abnormal voltages [15]. Therefore, it may be necessary to consider a wider variety of time delays in future work. Regardless, it is necessary to take this time delay into account when building a model, rather than having an inverter disconnect the instant the abnormality occurs.

TABLE I
INTERCONNECTION SYSTEM RESPONSE TO ABNORMAL VOLTAGES

Voltage range (% of base voltage[a])	Clearing time(s)[b]
V< 50	0.16
50 ≤ V< 88	2.00
110 < V < 120	1.00
V ≥ 120	0.16

[a]Base voltages are the nominal system voltages stated in ANSI C84.1-1995, Table 1.
[b]DR ≤ 30 kW, maximum clearing times; DR > 30kW, default clearing times.

This table is taken from IEEE 1547's table 1 [2].

In order to accurately simulate these time-delays, we need a measure of the likelihood that a particular inverter will disconnect given its prior history of voltage or frequency (note that the results in this paper come from a quasi-steady-state model and thus do not include frequency). In order to accurately capture this time-delay in simulations, we introduce the idea of 'overload area' (or just area), in which each inverter will disconnect when the accumulated under- or over-voltages area exceeds a pre-specified limit. The area is a function of difference between acceptable voltage and actual voltage, and the time that is allowed at that voltage. There is an upper voltage limit to the safe voltage range, V_H, as well as a lower limit, V_L, thus two functions were derived in order to account for the two situations.

At the beginning of each simulation in TiDIM, a maximum threshold area is calculated based on using both V_H and V_L which are then averaged together. The formulae to find these thresholds take the form:

$$A_{max} = a_1V^6 + a_2V^5 + a_3V^4 + a_4V^3 + a_5V^2 + a_6V + a_7, \tag{1}$$

where the coefficients, as derived from parameters in IEEE 1547, are listed in Table II. A different set of coefficients was calculated for both cases: $V = V_H$ and $V = V_L$. There is a very small number representing uncertainty, σ, around V_H and V_L, which is why this quantity is calculated every time the simulation is run rather than being a stagnant number. Once $A_{\max}$ is calculated, it is then constant for the rest of the simulation.

TABLE II
COEFFICIENTS FOR $A_{\max}$

coeff.	V_L	V_H
a_1	0	-49.408
a_2	-25.273	400.4
a_3	48.633	-1289.6
a_4	- 26.339	2062.3
a_5	5.2588	-1637.6
a_6	- 0.2528	515.38
a_7	0	1.1

Next, we need a way of deciding whether the accumulated area has exceeded the threshold $A_{\max}$ at each time step. To do so, at each time step t TiDIM uses the following difference equation:

$$A[t+1] = A[t] + A_n[t] \tag{2}$$

where $A[t]$ is the current amount of area accumulated and $A_n[t]$ is the new area accumulated at time step t. When voltages are within limits, $A_n[t] = 0$. When voltages our outside of the limits $A_n[t]$ has the form:

$$A_n[t] = 100(b_1V^6 + b_2V^5 + b_3V^4 + b_4V^3 + b_5V^2 + b_6V + b_7)\Delta t, \tag{3}$$

with the coefficients listed in Table III. 100 is the normalization factor. Because the equations for A_n are nonlinear, area accumulates faster when voltage strays further outside of the nominal voltage range.

TABLE III
COEFFICIENTS FOR A_n

coeff.	$V_{L,t}$	$V_{H,t}$
b_1	0	34.197
b_2	20.887	-252.19
b_3	-51.95	738.75
b_4	41.438	-1074.9
b_5	-6.8146	778
b_6	- 5.2201	-225.27
b_7	1.76	1.1

When a simulation is initiated, each inverter is given a custom value of $A_{\max,i}$, which deviates from the original $A_{\max}$ using a Gaussian random variable with mean 0 and standard deviation σ_A. When $A_i[t]$ exceeds $A_{\max,i}$, inverter i disconnects from the system. Because each $A_{\max,i}$ is slightly different, the inverters disconnect at a different time points during the simulation.

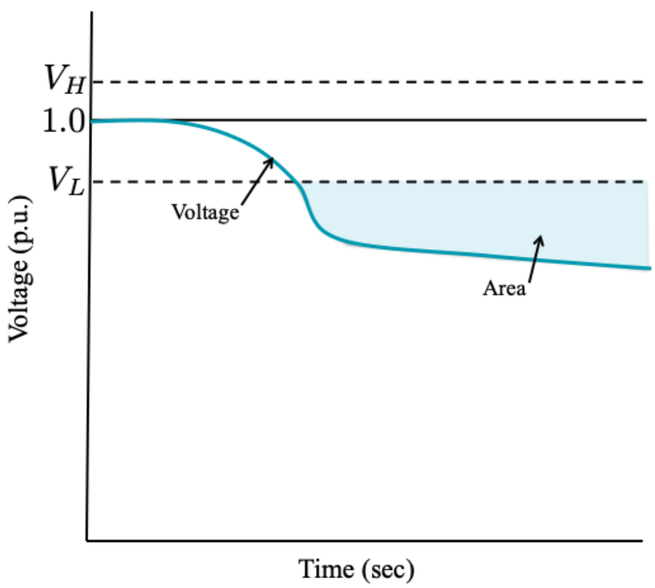

Fig. 1. Voltage and Area Accumulation

TiDIM also comes insured with accident forgiveness. If the voltage returns to the acceptable range, the accumulated area is set back to zero. If the voltage begins to stray again, the area accumulates from zero with no previous memory of past area.

IV. RESULTS

This section provides a set of results that illustrate the application of TiDIM to a two-bus test case.

A. Test Case

The test case used in this paper, shown in Figure 2, is a two bus model with a voltage-controlled generator at bus 1 and a large number of PV systems and a load at bus 2. In the pre-fault scenario, there are two identical transmission lines between the two buses. A simulation begins at $t = 0$. At $t = 0.1\text{sec}$, one of two parallel transmission lines faults and is immediately removed from service to introduce an initial

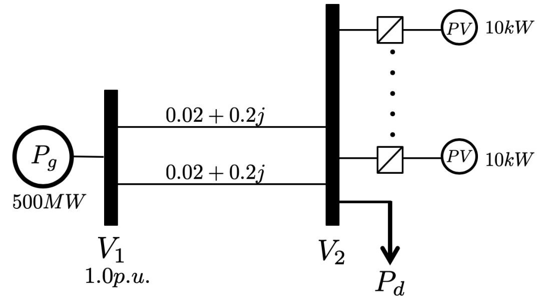

Fig. 2. Illustration of the two-bus test case used for simulations in this paper.

disturbance. The parameters for the base case can be found in Table IV.

TABLE IV
PARAMETERS FOR TEST CASE

Parameter	Value
$P_{d,0}$	500 MW
σ_A	0.4
X	0.2 p.u.
R	0.02 p.u.
N	50×10^3
kW/module	10

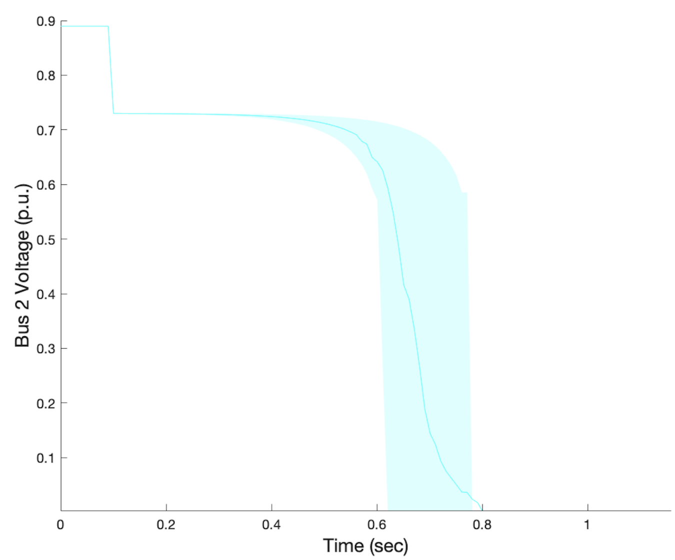

Fig. 3. Voltage at bus 2 in the base case simulation. Note that the shaded region in this and each of the plots represents the 5% to 95% percentile results.

Applying TiDIM to the test case and varying the various parameters allows one to understand the impact of these parameters on a power system. In Fig. 3 and each of the subsequent plots, the broad, shaded region shows the 5th and 95th percentile of possible outcomes from one set of initial conditions. The range is due to small sources of uncertainty within the initial conditions. The darkened line is the mean of the results for that set of conditions. The high voltage at the far left of the plot shows the pre-fault voltage. This plot shows that even with the same initial conditions, a wide range of results are possible. As previously mentioned, there is a σ_A for $A_{\max}$. The following parameters also have a small σ to represent variability in the value due to conditions or uncertainty of the exact value: V_L, V_H, and V_0.

B. Initial Load, $P_{d,0}$

Voltage collapse occurs when the net load at bus two exceeds the total transfer capability of the transmission path from bus 1 to bus 2. Hence, there is a critical point around $P_d = 480\text{MW}$ where the system is able to survive for a fairly long period of time without inverter outages that could lead to cascading failures. Due to the inverter parameter variability in TiDIM, there is no precise single value for the critical point. (If all σs representing variability in TiDIM are set to zero, then this inflection point is $P_d = 485\text{MW}$.) Before and after this point of precarious balance, the time to failure increases with the load and then decreases again once the load becomes too large (Figure 4).

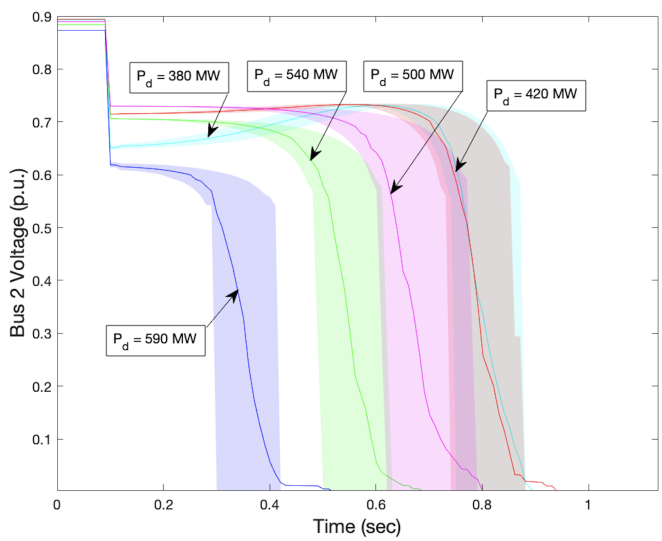

Fig. 4. Bus 2 Voltage over time with varying initial loads, $P_{d,0}$

C. Area limit variation, σ_A

The effect that σ_A has is two-fold, which can be seen in Figure 5. First of all, σ_A determines how long the system will persist before collapsing: a small σ_A leads to prolonged persistence, while a large σ_A leads to more imminent failure. When σ_A is small, this indicates that many of the inverters in the system are of the same demographic, and when σ_A is large, it indicates that there is a wide range of inverter type, brand, age, and so on. Secondly, σ_A changes the shape of the collapse curve. When σ_A is small, many of the inverters disconnect at the same time, which leads to a sudden voltage collapse. When σ_A is larger, the voltage collapses more gradually; although the collapse occurs relatively quickly because of some inverters having a low area limit, it is still not a sudden drop in voltage and may be easier to detect before it is too late to react.

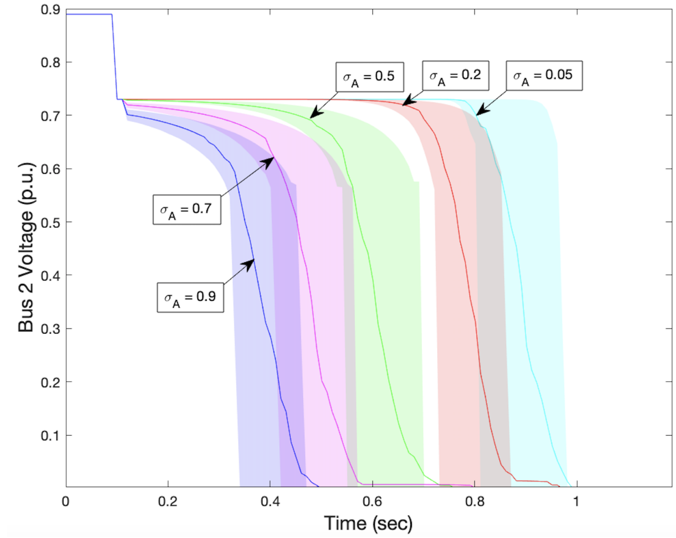

Fig. 5. Bus 2 Voltage over time with varying σ_A on area limits

D. Number of Inverters, N

The number of inverters is directly proportional to the power supplied by the PV sources, and additionally, we assume that all PV modules supply the same amount of power to the system, 10kw per installation.

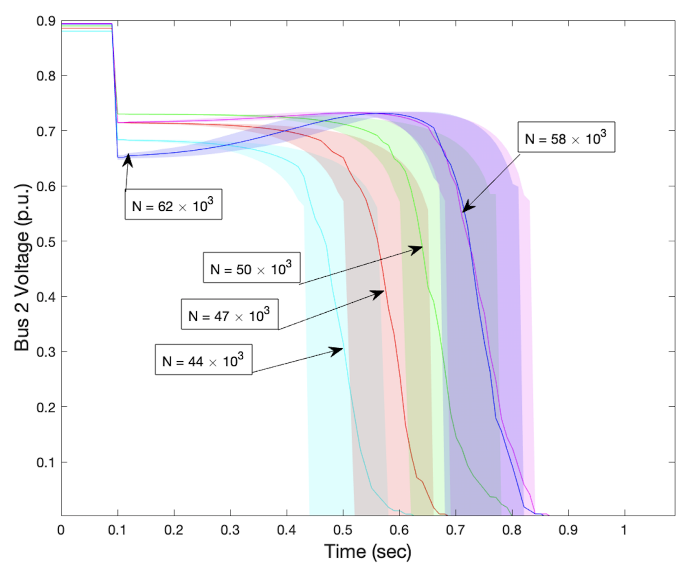

Fig. 6. Bus 2 Voltage over time with varying numbers of inverters, N

As with load, increasing or decreasing the number of inverters beyond the less-risky region led to a quicker voltage collapse in Figure 6.

E. Transmission Line Reactance, X

As one would expect, the effect of the reactance in the voltage collapse is quite significant, as seen in Figure 7. Over a relatively small range of reactance values, varying X can lead to anything from near immediate collapse ($X = 0.26\text{p.u.}$, not shown on plot) to no collapse at all. In fact, a mere

0.01p.u. is enough to swing the outcome from near certain safety to near certain failure. This result suggests that reactance (i.e., proximity to voltage collapse) strongly influences the likelihood of an inverter cascade.

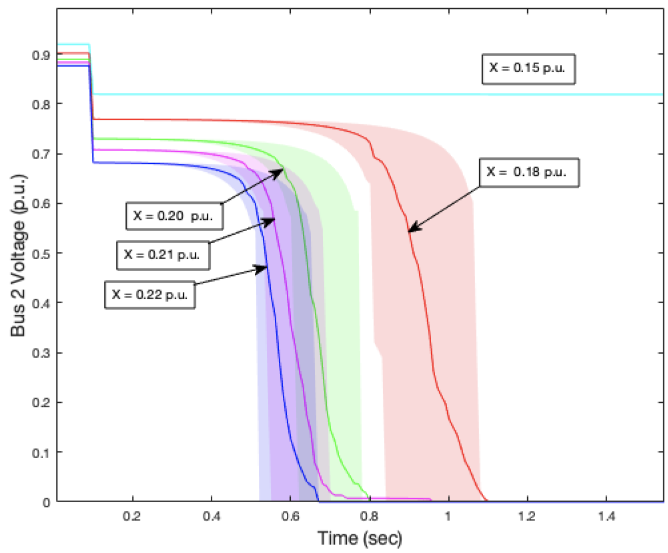

Fig. 7. Bus 2 Voltage over time with varying X

F. Transmission Line Resistance, R

While minute changes in X had a substantial impact on the likelihood of a cascade, changes in the resistance did not have such a drastic effect. Reducing R by an entire magnitude resulted in very little change (Figure 8). Increasing R resulted in some change (a quicker voltage collapse), but it is necessary to increase R by an order of magnitude from the test case resistance in order to get a significant change in the results. As would be expected from standard models of voltage collapse, changing R has a much smaller impact on cascading risk, relative to changing X.

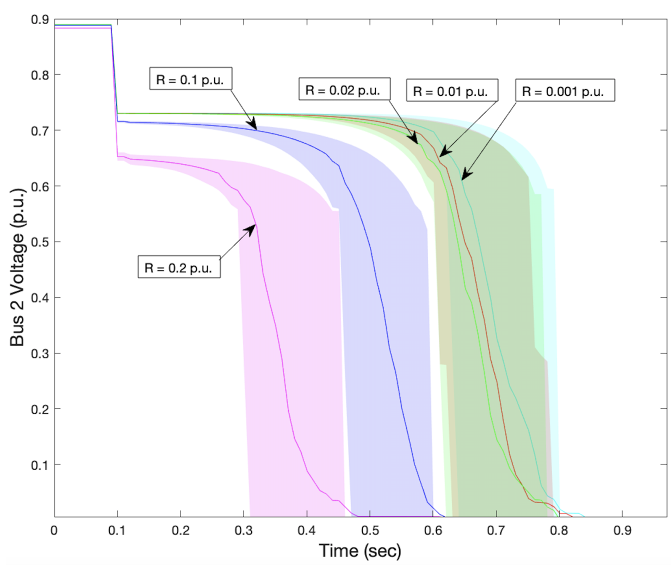

Fig. 8. Bus 2 Voltage over time with varying R

G. Non-significant parameters

Additional experiments were performed to understand the impact of varying σs on V_L, V_H, and V_0. The results suggest that these parameters have very little impact on the likelihood of a cascade.

V. Conclusions and Future Work

The results of the experiments run in this paper are summarized in Table V. From these results it is clear that a large reactance, a large resistance, and a larger σ_A can contribute to a higher risk of or an increased speed of cascading inverter failures. Among the reactance and resistance, the results confirm conventional power systems results, which would suggest that changes in reactance can dramatically change the risk of voltage collapse. Additionally, a large mismatch between load and power supplied by inverter-based sources can also contribute to a higher risk of failure.

It is our intention that as this model matures, TiDIM will enable engineers to better understand the conditions that lead to dangerous inverter failure cascades and use the insights that results to design systems that are more resilient to wide scale collapses. While the results from the two-bus test case used in this paper provide insight into the general problem of inverter cascades, we acknowledge that it is difficult to draw broad conclusions from a single, small test case. Future work will provide deeper insight into this problem through the use of more detailed dynamical models and larger test cases. Although the results from this early work are tentative, they provide useful insight into an important and timely power systems problem. Future work, in part discussed below, will expand on these results and provide more actionable engineering conclusions.

TABLE V
Results Summary

Parameter	Region of Increased Risk
σ_A	larger is riskier
N	dependant on typical demand
X	> 0.16 p.u.
R	> 0.03 p.u.

Another important component of inverter disconnection is not only the reaction to abnormal voltage, but also to abnormal frequency. In order to study this, a dynamic model needs to be developed where the frequency of the system can vary according the state of the grid. Future work will integrate frequency dynamics into TiDIM. Future versions of TiDIM will also include demand response in the form of a time-varying load profile. Future work will also include more complex networks, as a two-bus, two-line toy model can be useful but is limited in its scope to reflect the dynamics of a real world, multi-bus and multi-line system.

As previously mentioned, the uncertainty around the maximum area accumulation, σ_A, plays an important role in the behavior of cascading inverter collapse. In order to determine a realistic σ_A, some empirical inverter testing is needed to understand how factors such as manufacturer, age, and size influence the variance in inverter parameters. An additional complication is that based on geographic location, inverter parameters may differ significantly. For example, a particular neighborhood may have participated in a particular vendor's solar program and received the same PV modules and inverters at the same time, or perhaps a particular location was slow to adapt solar leading to wide range of time over which different models of PV systems were installed.

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