Voltage-based limits on PV hosting capacity of distribution circuits

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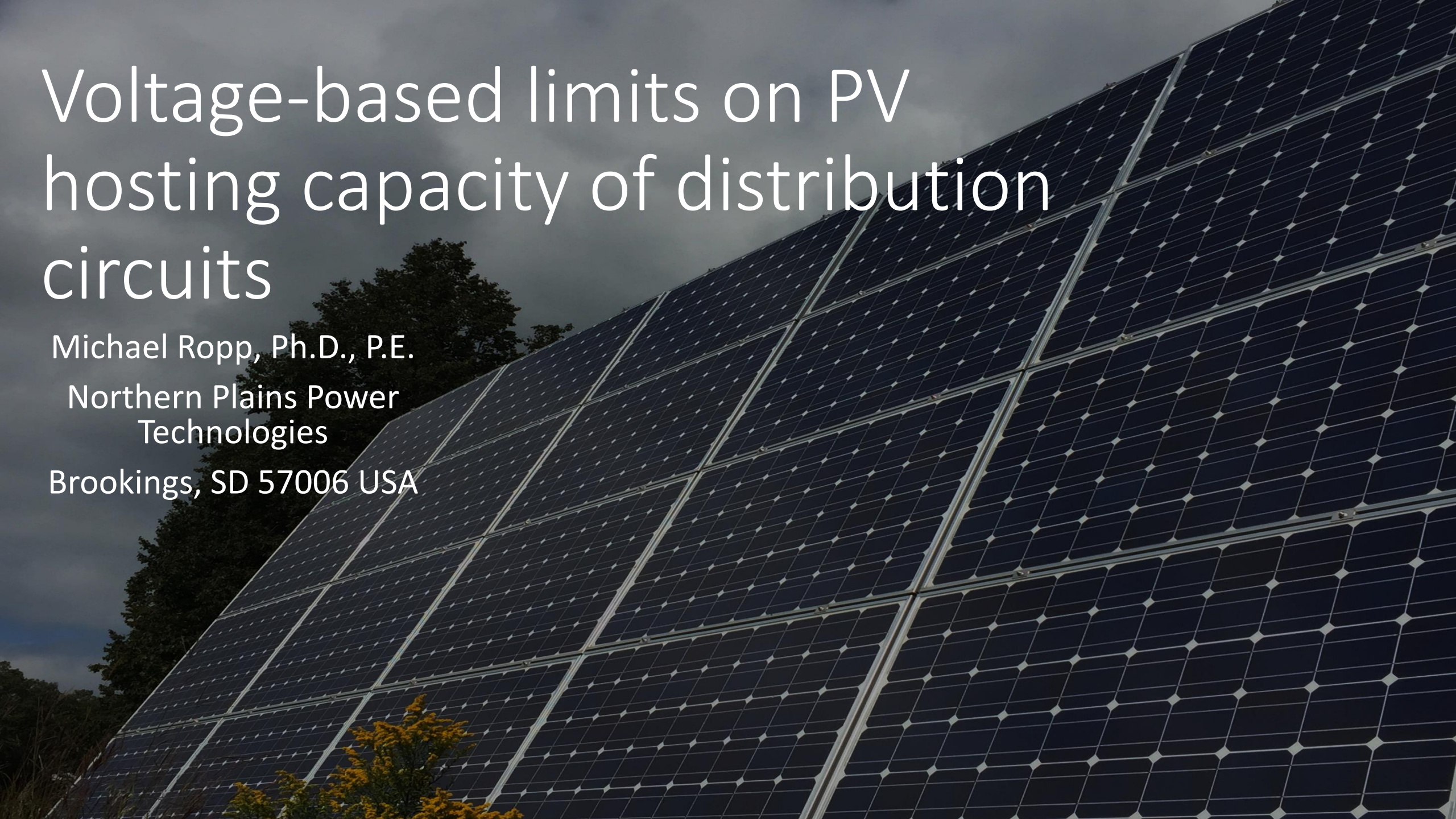

Brief description of NPPT

What we do

- Simulation studies for design, planning, compliance, analysis, characterization, owner's engineer
- Controls design, testing, diagnosis
- Protection/arc flash
- Testing (simulation and HIL)
- Event/root-cause analysis
- "Traditional" EMT-type studies

Application areas

- Energy storage systems
- Distribution automation/FLISR
- Low-inertia systems (island, remote community, military, microgrids)
- Distributed generation
- Utility scale PV/wind
- Overvoltage mitigation
- Harmonics/power quality
- Protection and arc flash, especially with DC and current-limited sources

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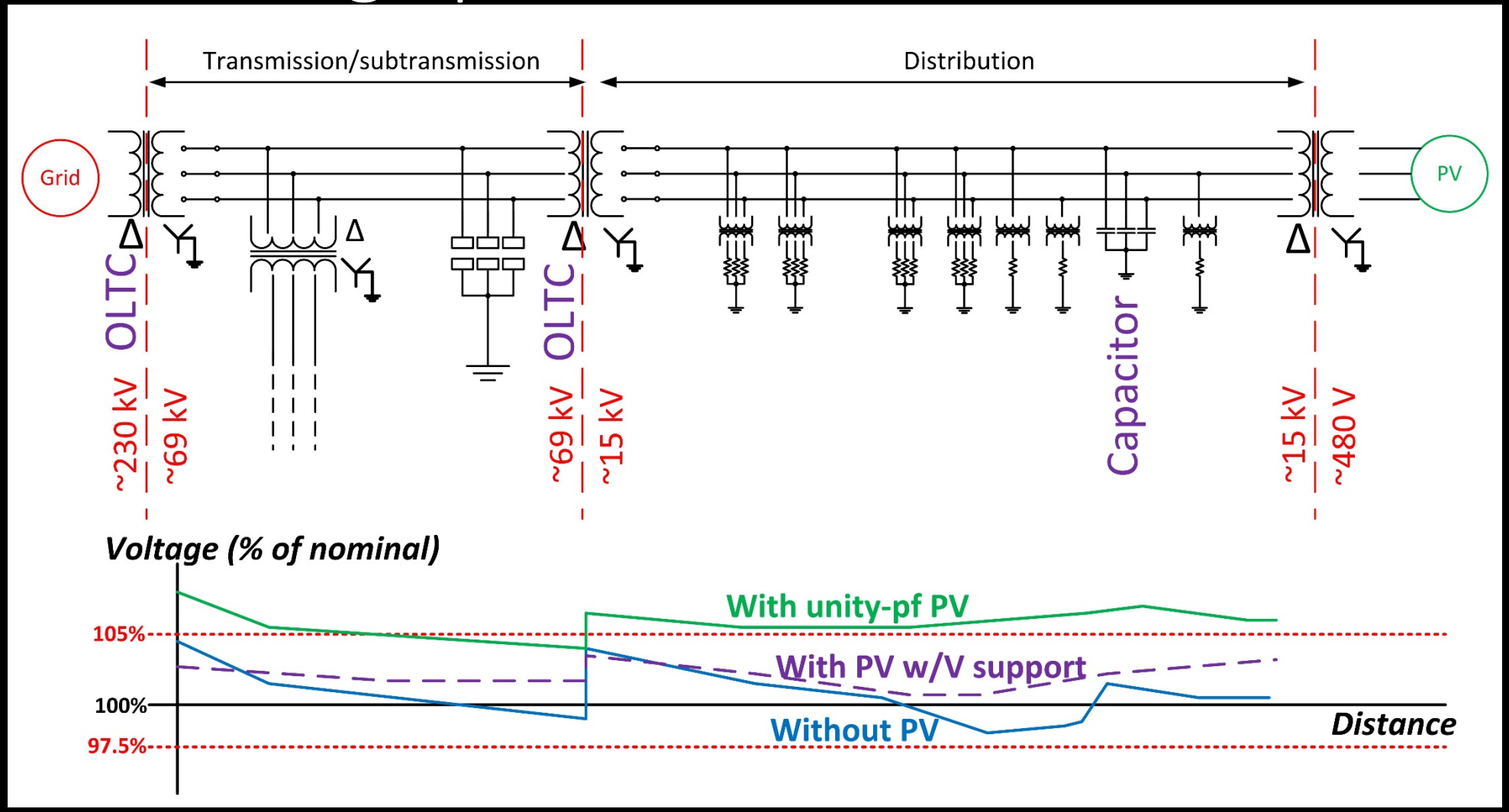
Distributed energy resources (DERs) and circuit voltage profiles

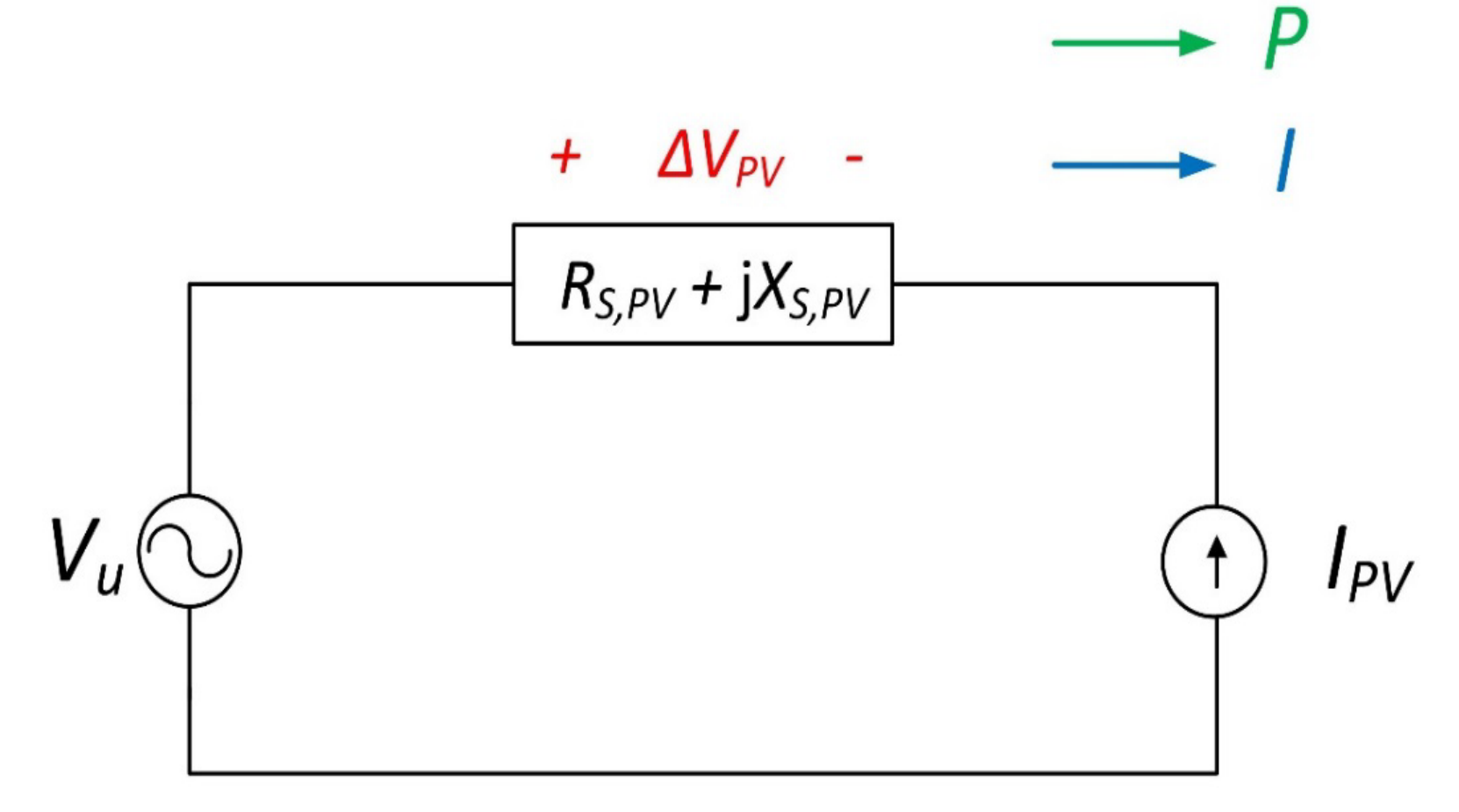


Avoiding voltage problems caused by DERs

- Ideally, we'd do a time-domain simulation of the circuit. Best physical fidelity, but a) need irradiance data, and b) expensive and time-consuming.
- Can study the situation. CYME/Synergi/WindMil and other distribution circuit simulators provide pretty good tools for this. However, a) not a true simulation, b) still need irradiance data, and c) still relatively time-consuming to do an 8760-type simulation.
- We need quick, simple design guidelines that can be used at the planning stage as compliance screens. Situations not resolved by this screen can still be studied further.

Simplified circuit model

The voltage rise at the DER site is primarily determined by the PV current and the source impedance as seen from the DER.



Circuit analysis

From the basic circuit model we can derive an equation that gives the voltage change at the PV PCC:

$$\frac{\Delta V_{PV}}{V_r} \approx \frac{\left(R_{S,PV} \times P_{PV}\right) + \left(X_{S,PV} \times Q_{PV}\right)}{V_r^2} + j\frac{\left(X_{S,PV} \times P_{PV}\right) - \left(R_{S,PV} \times Q_{PV}\right)}{V_r^2}$$

- ΔV_{PV} is the fractional change in voltage at the PV POI caused by the change in PV output;
- $R_{S,PV}$ and $X_{S,PV}$ are the real and reactive source impedance as seen from the POI of the PV plant in question looking back up toward the utility source;
- P_{PV} and Q_{PV} are the change in injected real and reactive power per phase at the POI, using the load sign convention noted in Figure 1 (i.e., power injected by the PV plant is negative); and
- V_r is the nominal voltage at the PCC.

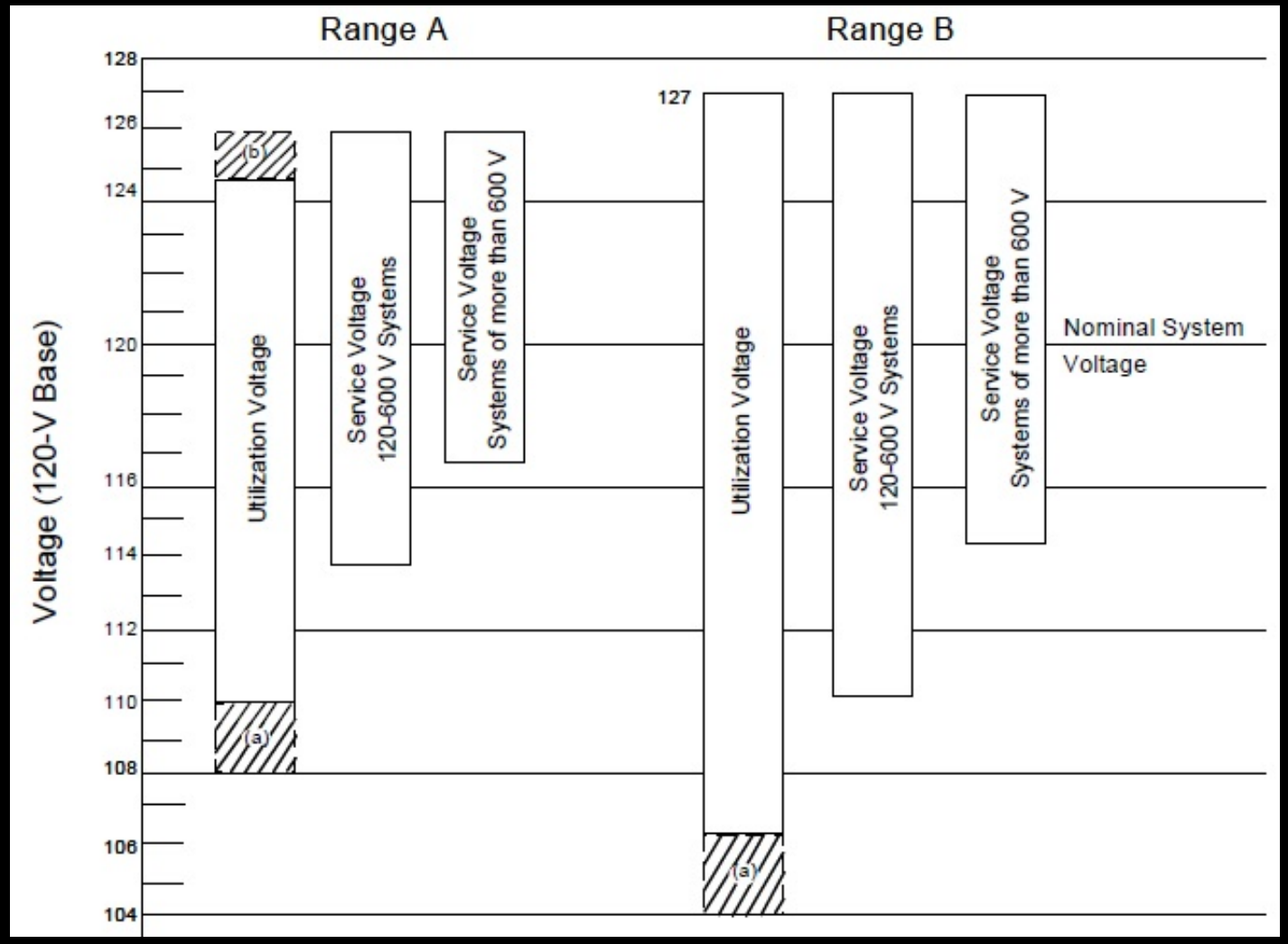
Simplify it

- If the PV is operating at unity power factor we can set the reactive output to zero.
- Also assume X/R is < 4.5.
- Then:

$$P_{PV,allowed} \approx \frac{\Delta V'_{allowed,PV} \times V_r^2}{R_{S,PV}}$$

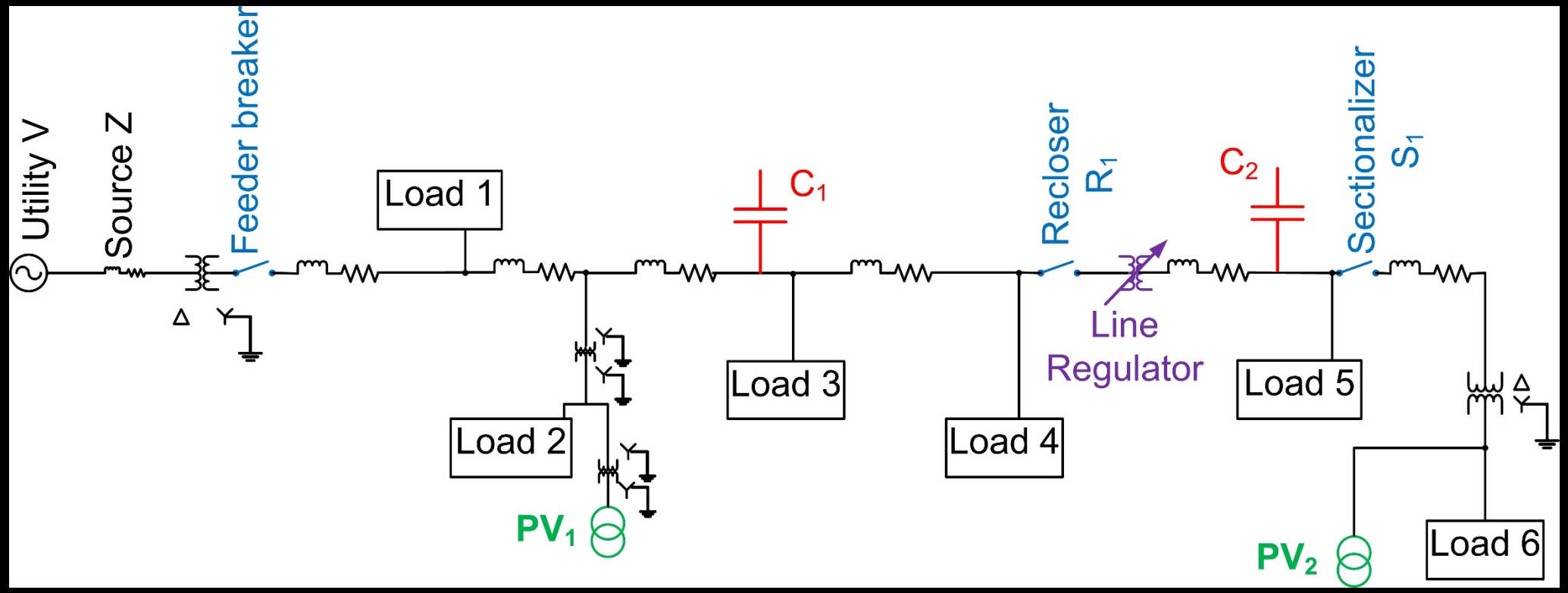
What should $\Delta V_{allowed}$ be?

For steady-state voltages, the ANSI C84.1 requirements apply. Range A applies at the PCC.



Another consideration: EMVR operations

Must also ensure that electromechanical voltage regulators (EMVRs) like line regulators and voltage-switched caps do not operate excessively when PV is added.



Minimizing the impact on EMVRs

- We need to minimize the ΔV caused by the PV plant at the EMVR location. The equation that gives this is essentially the same as that which gives the ΔV at the PCC:

$$\frac{\Delta V_{EMVR}}{V_r, EMVR} \approx \frac{\left(R_{S,EMVR} \times \Delta P_{EMVR}\right) + \left(X_{S,EMVR} \times \Delta Q_{EMVR}\right)}{V_r^2} + j\frac{\left(X_{S,EMVR} \times \Delta P_{EMVR}\right) - \left(R_{S,EMVR} \times \Delta Q_{EMVR}\right)}{V_r^2}$$

- This is the same equation as from the PCC, but with the source impedances as seen from the EMVR.

Recommended procedure: step 1

First, calculate the allowable PV plant size that keeps ΔV_{EMVR} within the control bandwidth of EMVRs <u>*upstream from the PV plant*</u>:

$$P_{PV,allowed} \approx \frac{\Delta V'_{allowed,EMVR} \times V_r^2}{R_{S,EMVR}}$$

where $\Delta V'_{allowed,EMVR}$ is a unitless fraction and is set equal to one-half of the control bandwidth of the affected EMVR. The control bandwidth is usually taken to be 0.0125 but may be as large as 0.03 in some cases. If the EMVR is using line drop compensation, that must also be considered.

Recommended procedure: step 2

Then, calculate the allowable PV plant size ensure that ΔV_{PV} does not lead to ANSI A violations using Equation (3) (repeated here for convenience):

$$\boldsymbol{P_{PV,allowed} \approx \frac{\Delta V'_{allowed,PV} \times V_r^2}{R_{S,PV}}}$$

with the value of $\Delta V'_{allowed,PV}$ as determined by:

$$\Delta V'_{allowed,PV} = 1.05 - V_{quad} - V_{PVbase}$$

where V_{PVbase} is the steady-state voltage at the PV POI after the PV reaches 0% power in the 100% to 0% power "trip test", and V_{quad} accounts for the neglect of the quadrature term.

That "V_{quad}" term

V_{quad} is intended to compensate for the neglect of the quadrature term in Equation (1). It depends on the ratio of $X_{S,PV}$ to $R_{S,PV}$ as follows:

$X_{S,PV}/R_{S,PV}$	V_{quad}
2	0.005
2.5	0.01
3	0.01
3.5	0.015
4	0.02
4.5	0.025

Step 3

The allowable PV plant size, assuming unity power factor operation, is the lesser of the values calculated in Steps 1 and 2. The $P_{PV,allowed}$ calculated in this way will be per-phase (multiply by 3 to get rated plant size).

Cases with EMVRs downstream from the PV

- For all locations downstream from the PV, the applicable ΔV is that seen at the PV PCC.
- However, if there are EMVRs downstream from the PV, the value of $\Delta V_{allowed}$ will be that associated with the EMVR (1/2 of the BW).
- In this case, the value of $P_{PV,allowed}$ can end up being quite small.
- Nonunity pf operation should definitely be considered in this case.

Mitigation of ΔV issues

- Constant nonunity power factor operation works very well, IF it can be done without violating a substation var flow constraint.
- For constant power factor, $Q_{PV} = k \times P_{PV}$ where k is a constant. Then we can rewrite Equation (1) this way:

$$\frac{\Delta V_{PV}}{V_r} \approx \frac{\left(R_{S,PV} P_{PV}\right) - \left(k X_{S,PV} P_{PV}\right)}{V_r^2}$$

Power factor for zero ΔV

If we solve that equation for the power factor at which ΔV becomes zero, we get

$$pf_0 = \cos\left(\tan^{-1}\left(\frac{1}{X_{S,PV}/R_{S,PV}}\right)\right)$$

Power factor to obtain $\Delta V'_{allowed}$

We don't actually have to obtain ΔV = 0, so in practice we could use

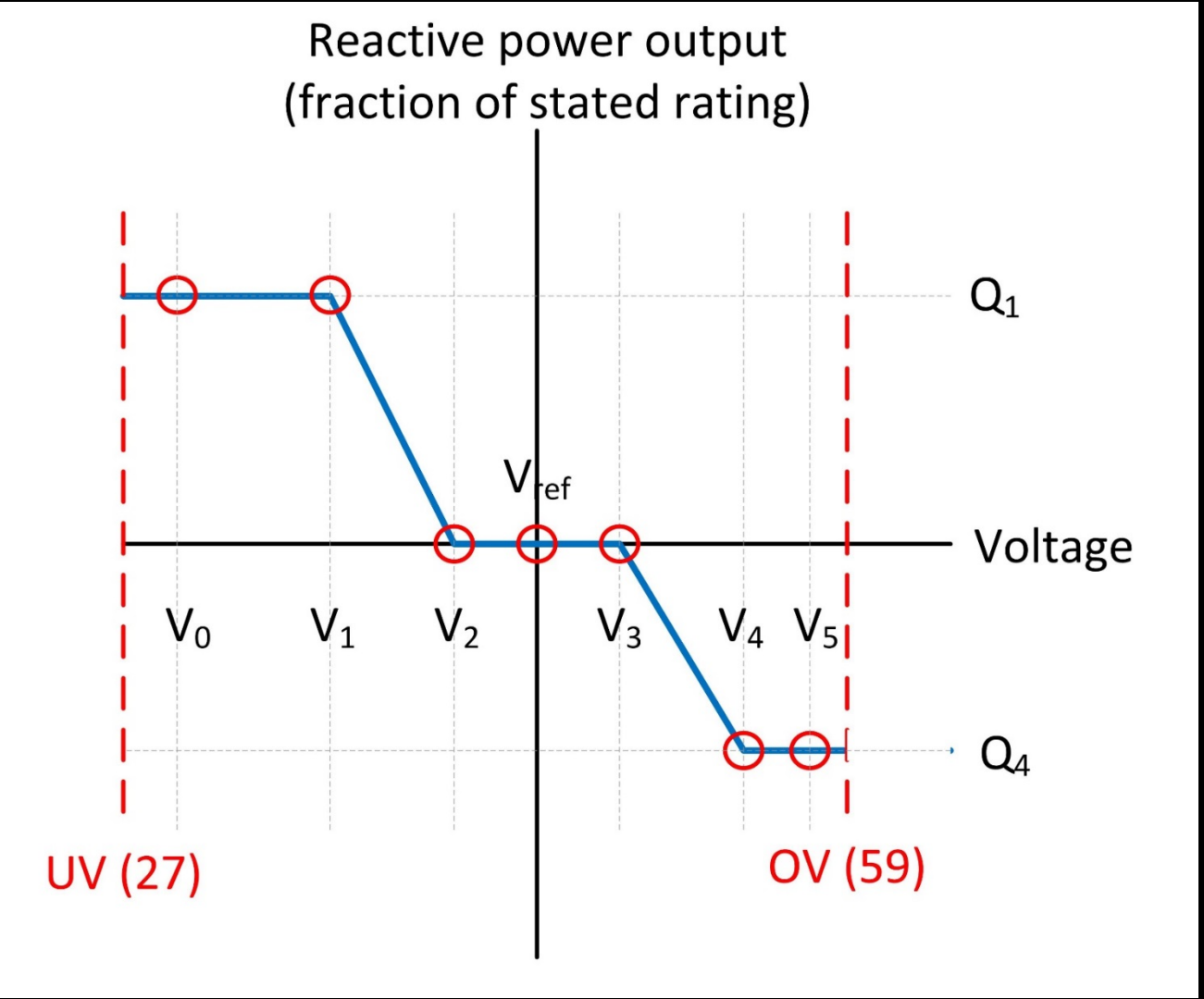
$$pf_0 = \cos(\tan^{-1}(\varphi))$$

where

$$\varphi = \frac{R_{S,PV} P_{PV} - \Delta V'_{allowed,PV} V_r^2}{X_{S,PV} P_{PV}}$$

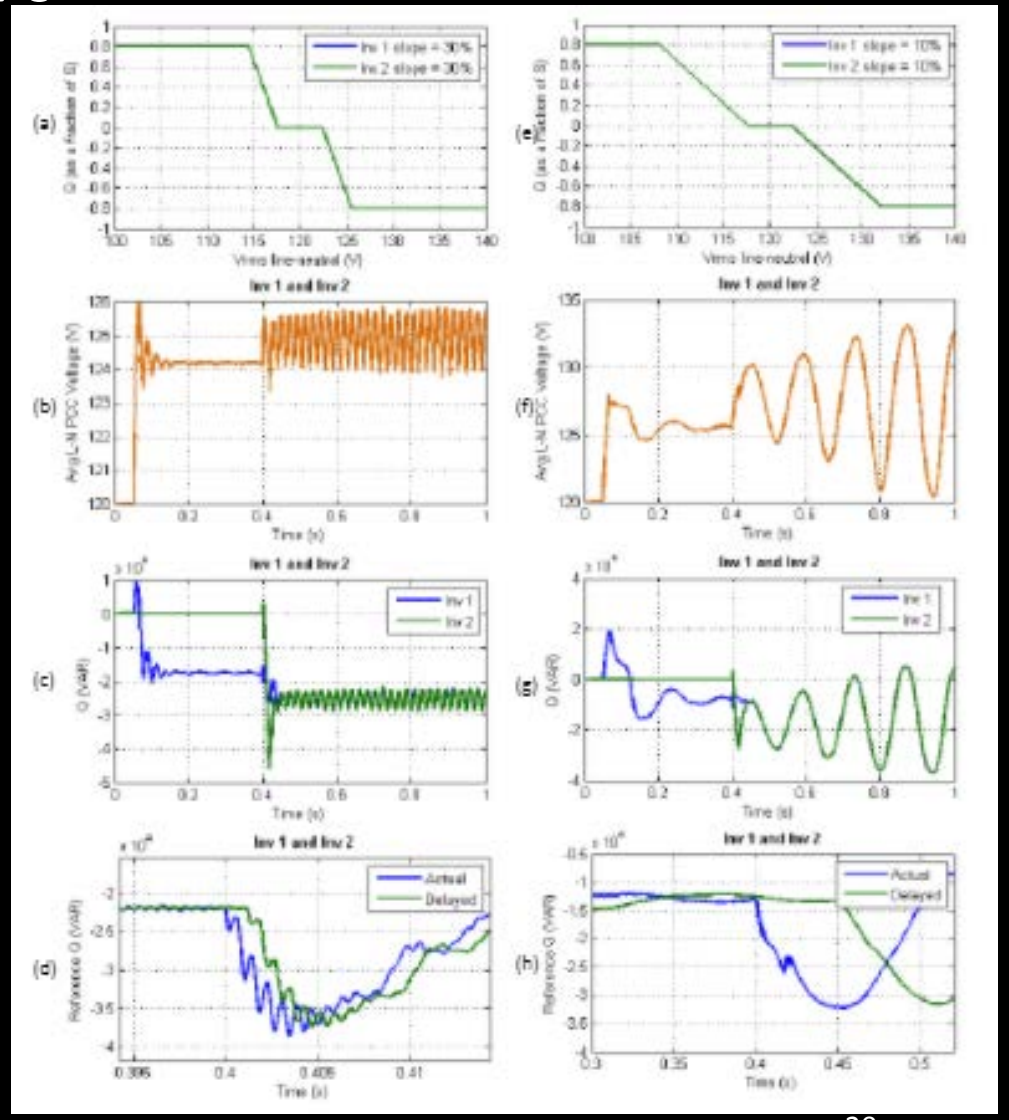
What about using "smart inverter" volt-var controls?

- IEEE P1547 will require all inverters to have the *capability* to implement a volt-var droop function like this one.
- Could we use this instead of fixed power factor? **Yes.**
- One challenge: ensuring that volt-var functions in multiple inverter plants do not oscillate with each other.



Inverters on the same circuit

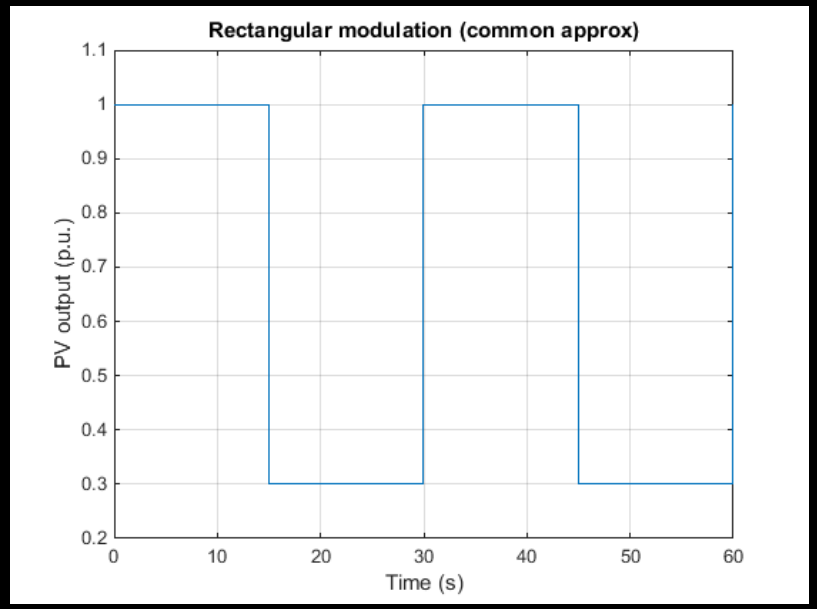
- It is well known at this point that it is possible for multiple volt-var controlling inverters on the same circuit to “chase” each other and oscillate. Factors:
  - Circuit impedance
  - Droop slope
  - Controller speed/response time
- Mitigation
  - Slow functions down
  - “Dynamic reactive current” or similar concepts

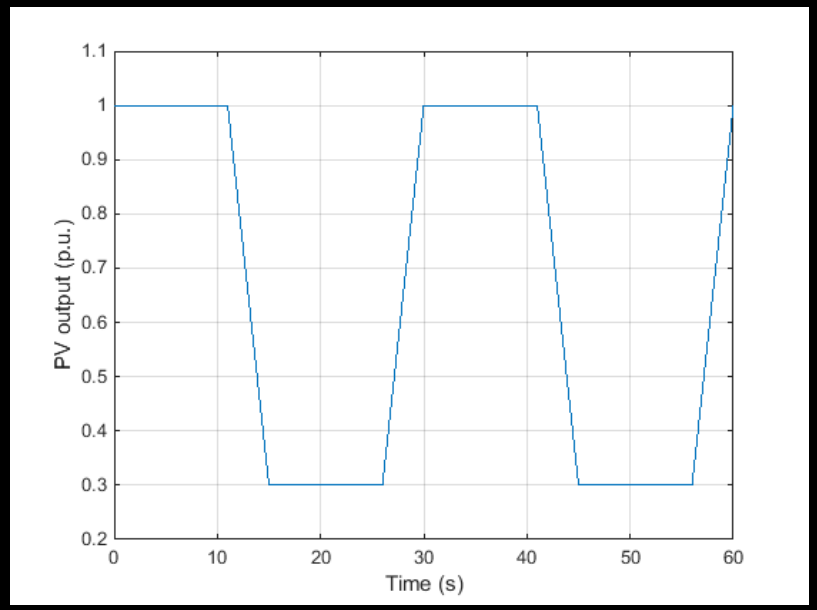


https://www.researchgate.net/publication/308822645_Evaluation_of_multiple_inverter_volt-VAR_control_interactions_with_realistic_grid_impedances

Flicker?

- The appropriate flicker standard is IEEE 1453-2015, which is based on IEC standards.
- The old "GE curve" assumed a rectangular modulation (top), but from cloud passages we'll have more of a "double ramp" (bottom).
- Bottom line: when you run this wave shape through the flicker meter, you find that the $\Delta V_{allowed}$ from flicker is larger than the ANSI C84.1 limits.
- Conclusion: **flicker is not a limiting factor in PV plant hosting capacity.**





What about RVCs?

- RVCs = Rapid Voltage Changes. Basically, a change in the RMS fundamental-frequency voltage that occurs very quickly, over only a few cycles (approximating a step change), while the system is in its normal operating ranges.
  - Tripping
  - Transformer energization
- IEEE 1453.1-2012 says:

Number of changes n	$\Delta U/U_N$ %	
	MV	HV/EHV
$n \leq 4$ per day	5-6	3-5
$n \leq 2$ per hour and > 4 per day	4	3
$2 < n \leq 10$ per hour	3	2,5

What about RVCs?

- For PV plants:
  - RVCs would be caused by tripping or transformer re-energization.
  - The n ≤ 4/day is the most appropriate value for that event. A PV plant producing more RVCs/day than that is malfunctioning.
- The suggested $\Delta V_{allowed}$ at an MV PCC would thus be 5-6%. IEEE P1547 adopted 5%.
- **One should apply this value to PV plants one at a time, not in aggregate.** The reason is that synchronized tripping would be expected only during abnormal system conditions, and that is outside of the scope/definition of RVCs.

Thank you very much!

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