DG Standard Updates

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Status Updates

CA Rule 21 Smart Inverter Phase 1 (Autonomous Features) Revision

- Approved by CPUC on 3/6/15

UL-1741 SA (CA Requirements)

- Draft procedure developed by task groups and being reviewed by UL staff for formatting prior to submittal for comment/approval by full UL-1741 STP.
- Forecast approval/issue in approximately 3 months.

IEEE-1547 full revision status

- PAR approved by IEEE SASB on March 27, 2014.
- Latest meeting at Arlington, VA on 2/10/15-2/12/15
- Forecast ballot date: Fall 2016.

CA Rule 21

Rule 21 Smart Inverter Phase 1 revision will be mandatory 12 months after UL-1741 SA is approved by UL-1741 STP.

Key features are as follows:

- Anti-islanding
- Extended ride through for voltage and frequency
- Dynamic Volt/var control
- Frequency-watt (Optional)
- Normal Ramp Rate
- Connect/Reconnect ramp rate
- Microgrid exemption on ride through

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UL-1741 SA

Developed specific test protocols for each required function in Rule 21

Using droop control for Volt/var control

Test each function for the full range of adjustability.

Test anti-islanding with the new settings.

Draft document to be send to the UL-1741 STP for comments and then for balloting.

IEEE-1547 Re-write

Used Germany documents and Rule 21 document as starting reference points.

Reconcile the requirements for inverter based generators and machine based generators to the extent possible.

Due to the different characteristics between inverter and synchronous generations, the current approach is to use two or more performance categories.

Work is on-going with 7 separate task groups and conference calls every week.

Underlying Drivers For Revising Standards

- Germany's 2012 effort to retrofit over 315,000 inverters at hundreds of millions of dollars to avoid potential system reliability impact at high DG penetrations
- Existing requirements specified in IEEE-1547 and CA Rule 21 are based on simplified low penetration methodology, similar to Germany, which may cause unintended consequences at high penetration scenarios.
- Desire to use potential inverter capabilities, to mitigate the potentially higher impacts and to improve distribution level service reliability, i.e. microgrids, and power quality.

Existing requirements

- The existing Rule 21 recognized that if the DG is operating within the existing distribution system design parameters, with no reverse flow, it has minimal system impact.
- It identified the low impact conditions (Initial Review Screens) and provided simplified requirements to allow small DG units at low penetration levels to be interconnected quickly so long as safety issues are addressed.
- Typically, there are sufficient existing design & operating margin to accommodate the small DG units when they do trip off-line. So, some over-trip of the DG was deemed tolerable at the local level. 15 years ago, the DG penetration was less than 1%.
- This significantly simplified the review/approval process and reduced the interconnect review time for the small units.
- Currently, the small NEM PV units less than 30 kW can be approved and interconnected in less than 5 WD.

Current status

- The vast majority of the existing inverters are designed for grid interactive mode, set at unity power factor, and certified not to operate when the grid is de-energized, i. e., certified anti-islanding, to address safety concerns.
- A major benefit of the simplified low penetration approach is that these inverters produced the maximum as-available energy by relying on the grid for voltage and frequency support, for storage, and back-up service when the DGs are not generating.

PG&E 2014 Statistics

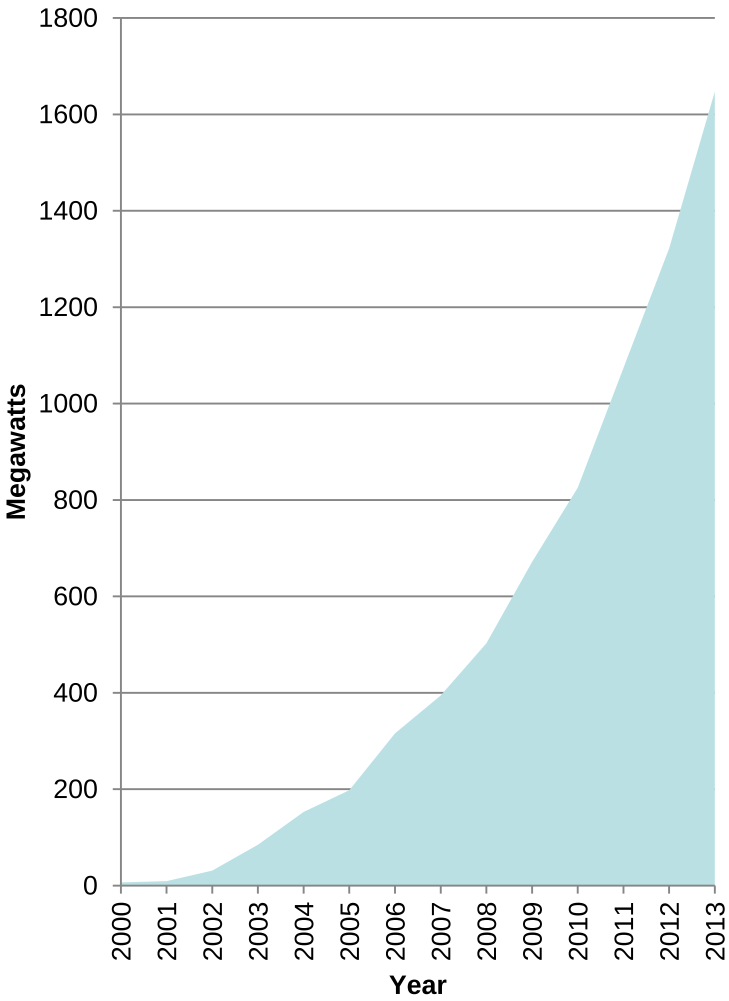
Service Territory

- 70,000 sq. miles with diverse topography
- 5.5 million electric customers
- 2013 Peak Demand is 21,000 MW
- Over 50% of PG&E's electric supply comes from non-greenhouse gas emitting facilities
- **144,000+ DG installations, mostly PV**
- 141,215 miles of distribution lines
- 18,616 circuit miles of interconnected T-lines

Distribution Equipment

- 3,231 Distribution Feeders
- 6,900 Line Reclosers
- 150,000 Fuses
- 14,500 Voltage Devices
- 1,100,000 Distribution Transformers

Total DG on PG&E System



PG&E's interconnection of distributed generation is growing exponentially.

DG Interconnection

- Total Installed DG Capacity = 1,775 MW
- Total Installed DG Customers = 144,000
- **System Penetration of DG Capacity = 8.4% of system peak load**
- **Feeder Penetration Data**
  - 8% of Distribution feeders have > 15% penetration
  - 3% of Distribution feeders have >30% penetration
  - 1.6% Distribution feeders have >50% penetration
  - 1% of Distribution feeders have 100% penetration

NEM Interconnections

- Median Cycle Time is 4 days from Application Complete to Permission to Operate (PTO)
- Issued 4,000 PTO notices in August,2014 with a projected 40,000 total for 2014
- No significant upgrades required to date

Existing Rule 21 Voltage Settings, still effective for non-inverter based DG.

Table D.1: Voltage Trip Settings		
Voltage at Point of Common Coupling	Maximum Trip Time(1)	
% of Nominal Voltage	# of Cycles	Seconds
Less than 50%	10 Cycles	0.16 Seconds
50% ≤ V < 88%	120 Cycles	2 Seconds
88% ≤ V ≤ 110%	No Trip	
110% < V ≤120%	60 Cycles	1 Second
Greater than 120%	10 Cycles	0.16 Seconds

Existing Rule 21 Frequency Settings, still effective for non-inverter based DG.

Table D.2: Frequency Trip Settings		
Generating Facility Rating	Frequency Range	Maximum Trip Time[(1)]
Less or equal to 30 kW	Less than 59.3 Hz	10 Cycles
	Greater than 60.5 Hz	10 Cycles
Greater than 30 kW	Less than 57 Hz	10 Cycles
	59.8 Hz > f > 57 Hz	10 - 18,000 Cycles[2,3]
	Greater than 60.5 Hz	10 Cycles

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Preparing for the future

- As California heads toward high renewable penetrations, the simple distribution interconnection requirements set up for low penetration, contained in IEEE-1547, UL-1741, and Rule 21, may need to be revised.
- At higher penetration, the cumulative DG impacts are no longer negligible and their aggregated impact to the grid during major disturbances has to be considered.
- Conversely, at higher DG penetrations, there also may be more opportunities to capture the potential benefits of DG, such as microgrids. It is expected that DGs may need to be monitored and controlled by the system operator at high penetration levels.

Phase 1 (Autonomous) DER Functions

The following autonomous DER functions will be mandatory in Rule 21 for smart inverter systems as Phase 1:

- Support anti-islanding to trip off under extended anomalous conditions
- Provide ride-through of low/high voltage excursions beyond current limits
- Provide ride-through of low/high frequency excursions beyond current limits
- Provide volt/var control through prescribed reactive power injection/absorption autonomously
- Define default and emergency ramp rates as well as high and low limits
- Provide/absorb reactive power by a fixed power factor
- Reconnect by “soft-start” methods

Table Hh.1: Voltage Ride-Through Table

Region	Voltage at Point of Common Coupling (% Nominal Voltage)	Ride-Through Until	Operating Mode	Maximum Trip Time
High Voltage 2 (HV2)	V ≥120			0.16 seconds
High Voltage 1 (HV1)	110 < V < 120	12 seconds	Momentary Cessation	13 seconds
Near Nominal (NN)	88 ≤ V ≤ 110	Indefinite	Continuous Operation	Not Applicable
Low Voltage 1 (LV1)	70 ≤ V < 88	20 seconds	Mandatory Operation	21 seconds
Low Voltage 2 (LV2)	50 ≤ V < 70	10 seconds	Mandatory Operation	11 seconds
Low Voltage 3 (LV3)	V < 50	1 seconds	Momentary Cessation	1.5 seconds

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Actual SCE FIDVR Event Data Used For VRT Settings

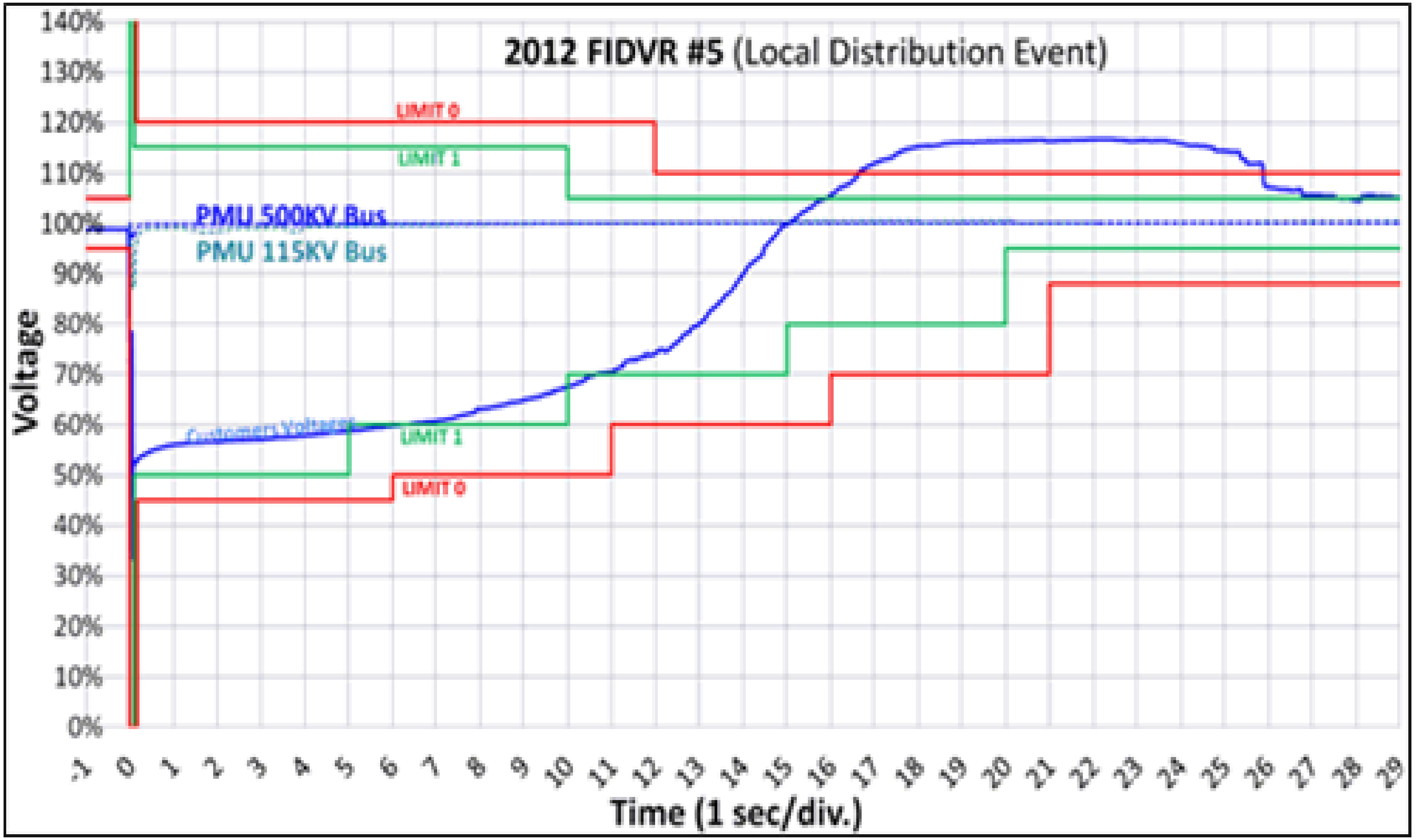

Table Hh.2: Frequency Ride-Through and Trip Settings

System Frequency Default Settings (Hz)	Minimum Range of Adjustability (Hz)	Ride-Through Until	Ride-Through Operational Mode	MaximumTrip Time
f > 62	62 - 64	No Ride Through	Not Applicable	0.16 seconds
60.5 < f ≤ 62	60.1 - 62	299 seconds	Mandatory Operation	300 seconds
58.5 ≤ f ≤ 60.5	Not Applicable	Indefinite	Continuous Operation	Not Applicable
57.0 ≤ f < 58.5	57 - 59.9	299 seconds	Mandatory Operation	300 seconds
f < 57.0	53 - 57	No Ride Through	Not Applicable	0.16 seconds

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Implementation challenges-
Phase 1 (Autonomous Functions)

- Developing the UL-1741 SA (California Requirements) smart inverter test procedure in parallel.
- The coordination between multiple units, utilizing active volt/var control, and with the existing voltage regulation equipment need to be verified to avoid potential voltage problems to existing distribution customers.
- Identify conditions where active volt/var feature will be useful and should be turned on.
- The existing anti-islanding schemes need to be tested at the new expanded V/F ride through settings and active Volt/var settings.

Expected Phase 2 (Communication-based Functions) Challenges

- Determine the expected penetration level.
- Determine the power system needs for various advanced SI functions.
- Determine the capability of the existing communication/control infrastructures to communicate with the SI.
- Determine the best communication/control architecture to communicate with the smart inverters.
  - Individual communication/control
  - Group communication/control
  - Combination of the above
- Determine what upgrades are needed to communicate and control the smart inverters at the lowest cost.
- Perform cost/benefit analysis for various scenarios.

Questions?

- More information about the SIWG, the specific Phase 1(autonomous functions), 2 (communication based functions) & 3 (advanced functions) recommendations, associated reference documents, and the CA Rule 21 revision text can be found on:
- http://www.energy.ca.gov/electricity_analysis/rule21/index.html

And

http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4565-E.pdf