LEVERAGING PHASOR-MEASUREMENT UNITS FOR GREATER SYSTEM VISIBILITY & PERFORMANCE

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ABSTRACT

Commonwealth Edison (ComEd) is leveraging S&C Electric Company's IntelliRupter® PulseCloser® Fault Interrupter and its highly accurate phasor-measurement capability to enhance visibility and increase real-time situational awareness of its distribution network. Phasor-measurement units (PMUs) are reliable time-synchronized devices that provide optimized grid monitoring. The utility is building these capabilities to support Distributed Energy Resources (DERs), real-time system operations and critical-infrastructure monitoring.

CUSTOMER BACKGROUND

ComEd delivers power to most of northern Illinois, including the Chicago metropolitan area. It manages more than 90,000 miles of power lines to serve 70% of the State's population.

ComEd uses approximately 2,500 S&C IntelliRupter® fault interrupters as the primary protection devices on its feeders. The utility achieved 0.09475 in System Average Interruption Frequency Index (SAIFI) and 1.675 minutes in Customer Average Interruption Duration Index (CAIDI) improvements using the fault interrupter's superior segmentation and loop-restoration capabilities.

ComEd has been implementing multiple modernization projects to ensure it is ready to meet clean energy goals and maintain a stable electric distribution system in a changing energy landscape. These projects play a pivotal role in integrating existing equipment on ComEd's distribution system with new, innovative technology to prepare the grid for future demands.

Leveraging valuable input from ComEd, S&C developed the IntelliRupter fault interrupter's phasor-measurement capability to enhance the visibility and situational awareness of the utility's distribution network. The IntelliRupter fault interrupter's phasor-measurement capability will use ComEd's extensive fiber communication network to allow for maximum bandwidth and fast data-streaming capabilities. ComEd plans to pilot this technology in Chicago's first microgrid, the Bronzeville Community Microgrid.

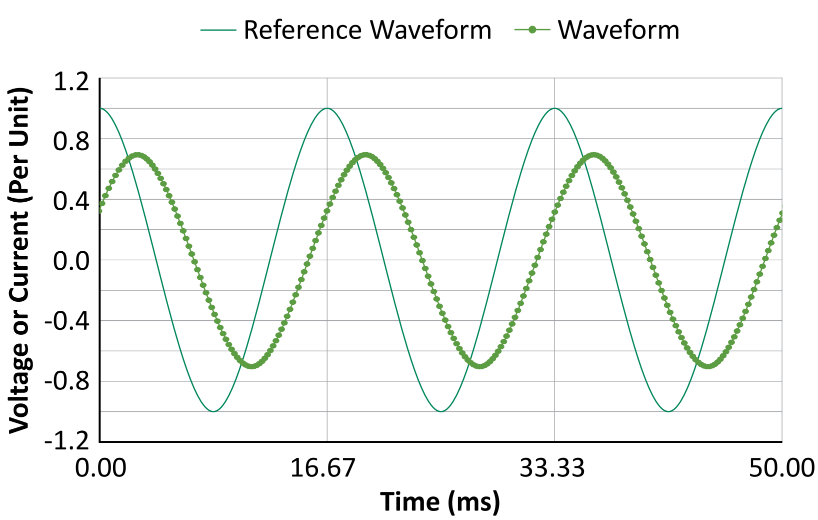
WHAT ARE PMUs?

PMUs capture power system voltage and current signals and convert them into values called phasors. Utilities can use phasor values from various points on a distribution feeder to monitor the power flow across its system and identify system abnormalities. These values are then time-stamped with a synchronized GPS clock.

Figure 1 shows the waveforms for synchrophasors in a chart and how synchrophasor values are calculated.

FIGURE 1. Synchrophasor waveforms and the formula to calculate synchrophasor values.

Additional information about this figure is available in the appendix.



$$x(t) = A\cos(\omega t + \varphi)$$

magnitude **frequency** **phase**

$$v(t) = \mathbf{V}\cos(\boldsymbol{\omega} t + \boldsymbol{\varphi})$$

$$i(t) = \mathbf{I}\cos(\boldsymbol{\omega} t + \boldsymbol{\theta})$$

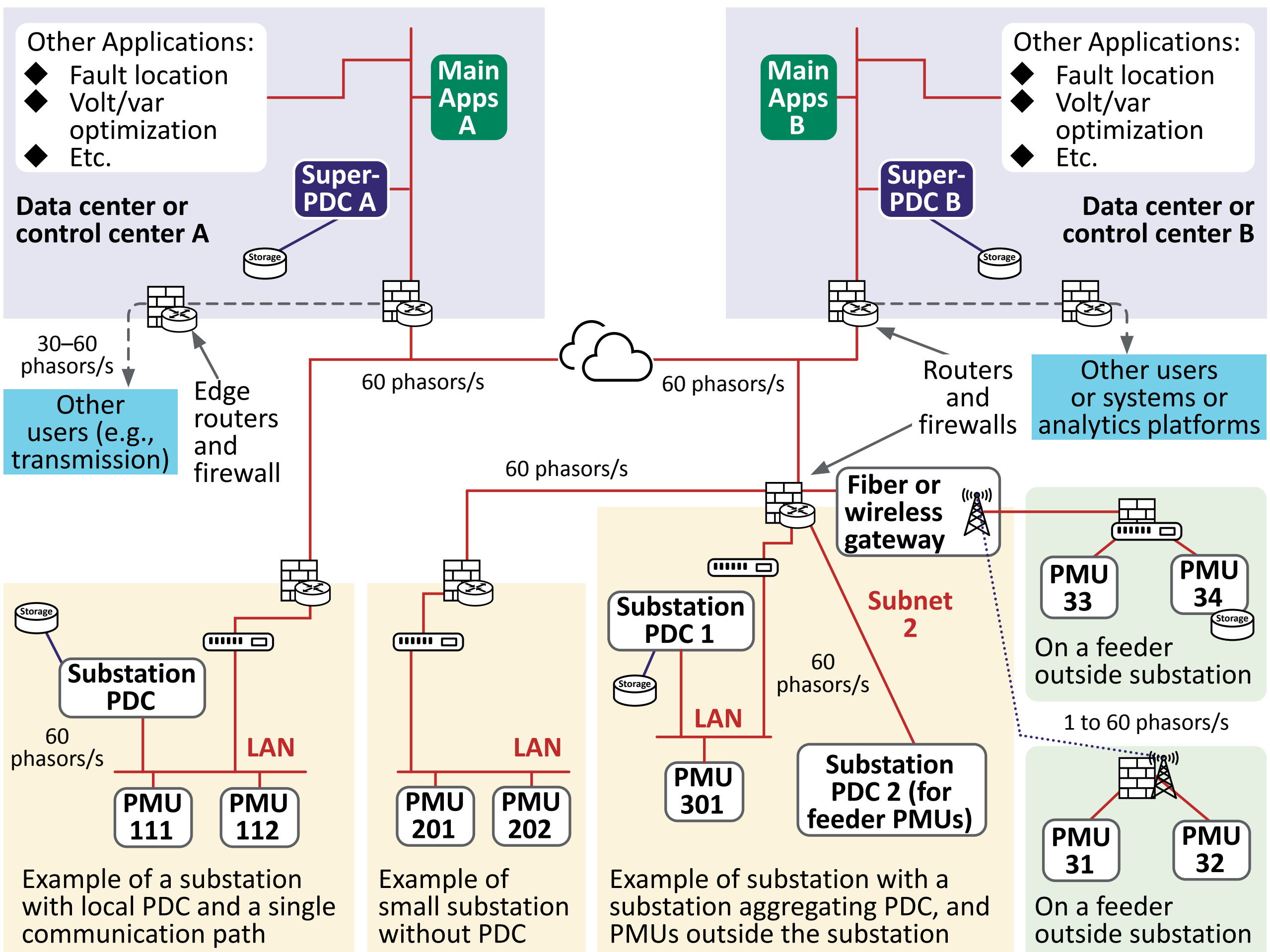
Time-synchronized phasor measurements are called synchrophasors. Synchrophasors measure distribution systems by providing time-synchronized measurements of three-phase voltage, current and frequency, as well as rate of change of frequency (ROCOF).

These measurements are governed by the IEEE/IEC 60255-118-1 standardized requirements and allow PMUs to stream them across a high-speed communication network (typically a fiber-optic network) to a phasor data concentrator (PDC) in a substation or at a network operations center. Because PMUs are measuring and streaming phasor data at an extremely high rate, a reliable high-speed communication architecture is crucial to the efficient operation of these devices.

Figure 2 is a high-level flow diagram showing the connectivity of synchrophasor data from the PMUs in ComEd's substations or on its feeders to a central data-storage and applications platform.

FIGURE 2. The connections between PMUs and PDCs on ComEd's system.

Additional information about this figure is available in the appendix.



Synchrophasor measurements in conventional recloser applications have not been reliable indicators of voltage, current, and frequency measurements because these devices have typically been designed to measure protection operations, not accurate phasor monitoring.

However, the IntelliRupter fault interrupter's Rogowski coils and its capacitive voltage sensors contribute to its highly accurate simultaneous bi-directional sensing capability. Ultimately, this capability allows the fault interrupters to produce highly accurate phasor measurements.

The fault interrupter's phasor-measurement capability also allows it to automatically send GPS time-stamped data to PDCs. The data provides increased system awareness so system operators can make quicker and better decisions to support wide-area protection schemes for faster and more reliable operations.

The data in **Table 1** and **Table 2** show the sensing accuracy of IntelliRupter fault interrupters compared to conventional reclosers.

TABLE 1. IntelliRupter Fault Interrupter Accuracy

Current Level	# of data points	Voltage TVE Median	Voltage TVE Max	Current TVE Median	Current TVE Max	Frequency Error (Hz) Median	Frequency Error (Hz) Max	ROCOF Error (Hz) Median	ROCOF Error (Hz) Max
80 A	1139	0.28%	0.30%	0.17%	0.47%	0.00016	0.00061	0.00342	0.01790
300 A	1252	0.28%	0.30%	0.13%	0.27%	0.00016	0.00068	0.00342	0.01628
600 A	966	0.28%	0.30%	0.11%	0.23%	0.00017	0.00066	0.00326	0.01790
1000 A	1253	0.27%	0.30%	0.16%	0.35%	0.00016	0.00061	0.00342	0.01563
1200 A	1772	0.27%	0.30%	0.15%	0.35%	0.00016	0.00061	0.00342	0.01742

TABLE 2. Conventional Recloser Accuracy [1]

Voltage Transformers

Accuracy Class	Max Magnitude Error	Max Angle Error
1.2 [2]	1.2%	~2 Deg
0.6 [2]	0.6%	~1 Deg
0.3	0.3%	~0.5 Deg
0.15	0.15%	~0.125 Deg

Current Transformers

Accuracy Class	Max Magnitude Error	Max Angle Error
1.2 [2]	2.4%	~2 Deg
0.6 [2]	1.2%	~1 Deg
0.3	0.6%	~0.5 Deg
0.15	0.3%	~0.25 Deg

1 Based on C57.13 and C57.13.6 standards.

2 1.2 and 0.6 class are commonly used in conventional reclosers.

As is evident from these values, the accuracy of the IntelliRupter fault interrupter's current measurements surpass that of the best conventional recloser by an order of magnitude. The accuracy of the IntelliRupter fault interrupter's voltage measurements is rivaled only by a conventional recloser using the highest accuracy transformer available. In practice, however, the highest accuracy voltage transformers are reserved for high-accuracy metering applications. The IntelliRupter fault interrupter's voltage readings are typically two to four times more accurate than those of a conventional recloser in the field.

PMUs revolutionize the way distribution systems are monitored. Because synchrophasors process distribution system data at an extremely high rate (10–120 frames per second), they provide more detailed and timely system visibility than traditional SCADA systems (which process one data measurement every 3–4 seconds).

Synchronized phasor measurements give utilities important insight into the flow of energy and equipment status to provide real-time situational awareness of the distribution system. Ultimately, PMUs give ComEd a simplified snapshot of its system's present health quickly and enable it to anticipate future potential system conditions.

PILOTING PMU-BASED APPLICATIONS

ComEd is presently pursuing several applications (e.g., DLSE, PMU-based fault detection and fault distance identification, etc.) with multiple possible use cases to test and validate the performance of its distribution PMU program, which will include data from the IntelliRupter fault interrupter's phasor-measurement capability. The goal is to find the best locations to deploy the fault interrupter's phasor-measurement functionality on its system moving forward to reap the greatest benefits that PMUs provide.

Deploying PMUs on its distribution system is part of ComEd's long-term strategy to better incorporate advanced monitoring equipment and software into its modeling and operational systems. ComEd is continuing this initiative by piloting these applications with the IntelliRupter fault interrupter's phasor-measurement capability:

Upgrading Substations

ComEd identified several key substations for its first PMU deployment. The utility's engineering team conducted a detailed review to determine which of hundreds of substations would yield the most meaningful data. The team first screened substations for baseline requirements, such as physical space, fiber backhaul capacity, and battery plant capacity. From there, considerations such as proposed DER growth, load profile, and implementation cost were considered in the final judgment on the viability of the substations for PMU technology.

ComEd's engineering team identified specific relays to upgrade in each substation so it could obtain full situational awareness at the distribution level. The utility's engineering and material teams created specific processes for PMU-ready relay packages and PDCs. The result was a relatively consistent topology that includes the placement of a PDC at each substation that was a good fit for PMU technology.

For some substations, only a handful of feeders were included, while for others every feeder received its own relay upgrade. The substations also had their protection improved with supervised undervoltage/overvoltage schemes. The design upgrade also included a server cabinet, power distribution system, SEL-3573 PDC, networking equipment, and GPS clock.

Since its inception, 22 substations have been upgraded with 220 PMU streams.

Monitoring Microgrid Performance

Because islanded microgrids do not have the support of the main grid, they require fault protection that can rapidly detect slight changes in voltage and reverse current.

The IntelliRupter fault interrupter's simultaneous bi-directional sensing and phasor-measurement capability will enable it to immediately identify and isolate faults in ComEd's microgrid and send event data to the utility simultaneously so it can manage the issue. ComEd piloted a new, pole-mounted micro-PMU (µPMU) enclosure in the Bronzeville microgrid.

The µPMU (see **Figure 3**) was designed specifically for microgrids but can be used in other applications on the distribution system. It was built on the PQube 3 Power Analyzer from Power Standards Lab, which measures voltage and current waveforms with 512 samples per cycle. In µPMU mode, the device reports a phasor (magnitude and angle) describing each waveform, with two samples per cycle, or 120 samples per second.

FIGURE 3. A close-up of a micro-PMU and a micro-PMU inside an enclosure.

GPS timestamping is used to synchronize the phasor measurements across locations. The µPMU timestamping has microsecond-level accuracy. This allows the µPMU network to measure the very small phase differences that are typical in microgrids.

The main physical components of the µPMU system are:

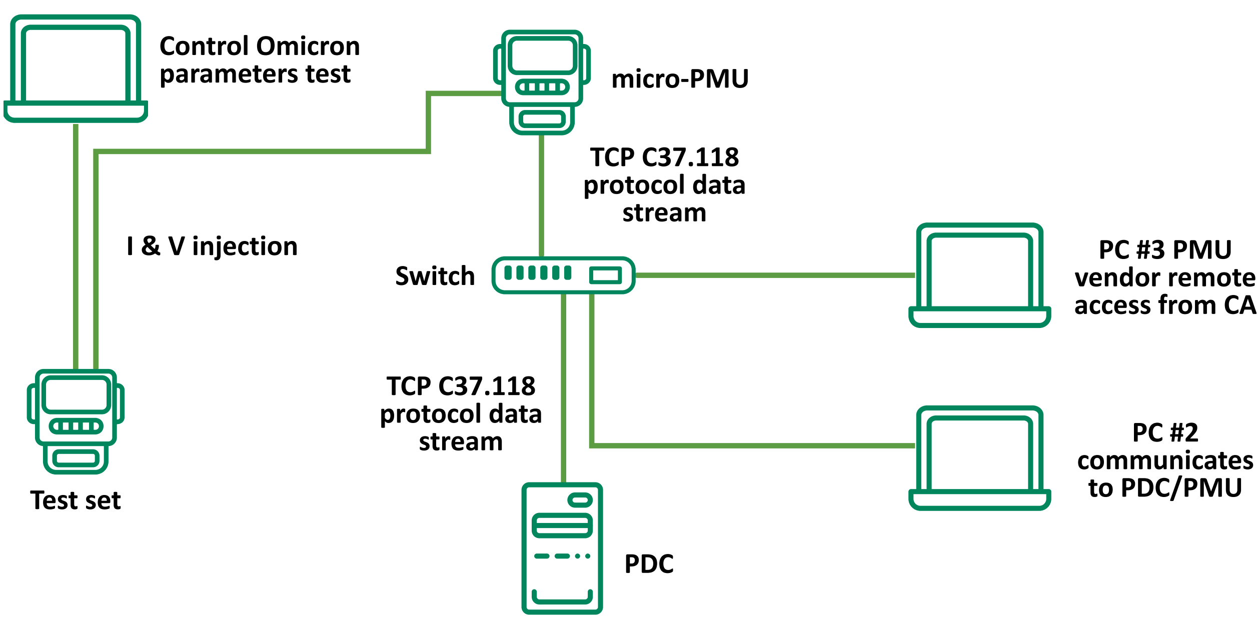
- A µPMU
- A GPS receiver
- An Ethernet connection, or a cellular modem, and antenna
- Potential and current transformers
- A hardware enclosure
- A data network server

To validate that its PMU communications were accurately established before field deployment, ComEd's Smart Grid team performed extensive testing in the utility's Maywood Grid Integration & Technology (GrIT) lab. The network topology of the lab is shown in **Figure 4**.

The goal with this testing was to emulate field topology and to test the µPMU's performance over their communications network. The testing included this data-streaming path as connected in the field: *PMU>SecFlow>Router on the pole>PDC*.

FIGURE 4. A topology of the micro-PMU network in the GrIT lab.

Additional information about this figure is available in the appendix.

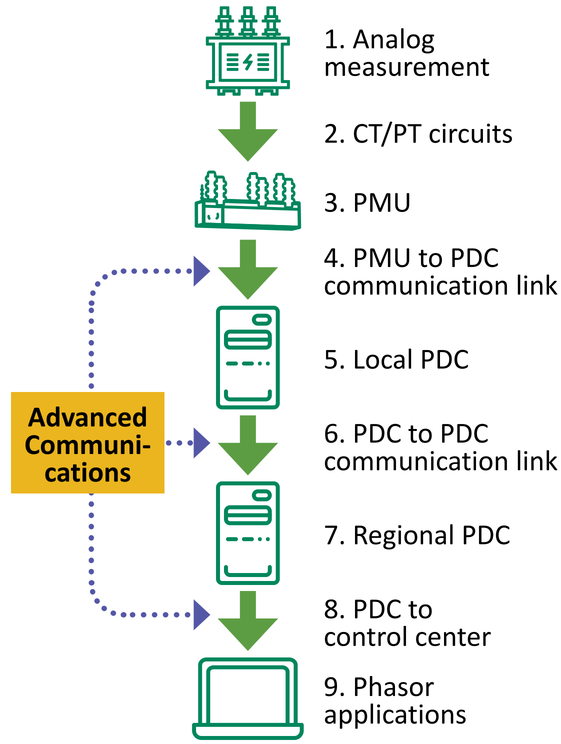


After successful lab testing, 25 micro-PMUs were deployed to enhance situational awareness and visibility of the Bronzeville microgrid through granular PMU measurements. These micro-PMUs were deployed along two distribution feeders in the microgrid's footprint. **Figure 5** shows what a micro-PMU installation looks like, and **Figure 6** shows the typical data flow for PMU communications in the field.

FIGURE 5. A typical micro-PMU pole installation.

FIGURE 6. A typical data flow path for Field PMU communications.

Additional information about this figure is available in the appendix.



Improving the Distribution System Holistically

ComEd developed a road map and strategy for the widescale use of PMUs in its distribution system. The key drivers of this program are to enhance operational efficiency, to gain the ability to scale DER integrations, and to drive the integration of new and emerging technologies.

The increased penetration of DERs and electric vehicle chargers on the system causes bi-directional power flow, which makes detecting and locating faults challenging. The strategic deployment of PMUs can enable distribution grid operators to take swift remedial actions, empowering a resilient, DER-rich distribution grid operation.

The need for more advanced outage management and remediation, faster and more sensitive fault detection, greater awareness of the state of the distribution system, and an ability to manage more DERs is expected to further drive a need for more granular and synchronized grid monitoring.

Because distribution PMUs measure data extremely quickly, they provide real-time snapshots of distribution systems with high DER penetration. This ensures faults are detected immediately, before they worsen, and that an event notification is sent to another device (such as a relay, inverter, or overcurrent control). PMU measurements give ComEd the ability to better understand how DERs interact on their distribution system.

Leveraging data from its first use case, the Bronzeville microgrid, ComEd identified the best use of the devices across its distribution system. To help estimate the real-time state of a distribution system utility, ComEd developed the North America's first Distribution Linear State Estimator (DLSE).

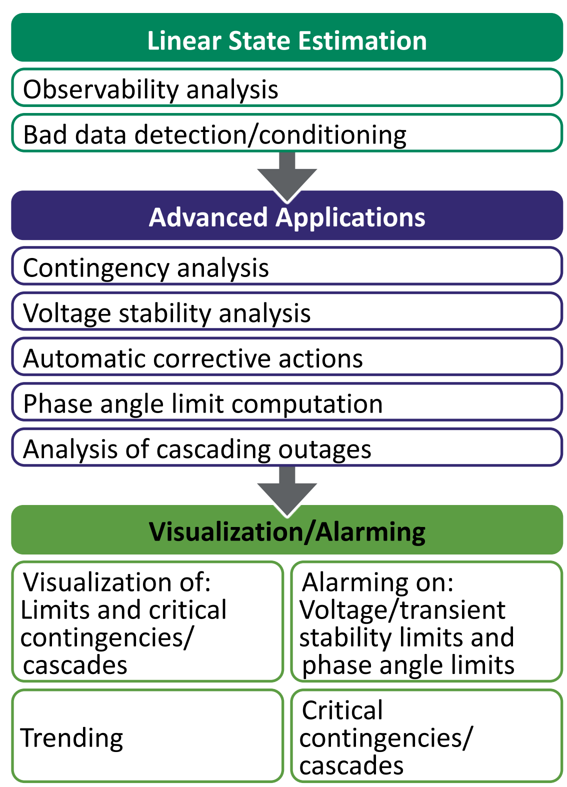
The DLSE is based on real-time PMU data to model the behavior of the distribution system under certain conditions. The DLSE was tested and validated in ComEd's GrIT lab through simulation and is being deployed at the Bronzeville microgrid by using field micro-PMU data. State estimation will ultimately give ComEd a solution for increased observability to support real-time situational awareness and monitoring, control, optimization, and time-sensitive applications (such as adaptive protection) on its distribution system.

The DLSE performs state estimation as fast as PMUs, up to 120 times per second, compared to traditional state estimation, which performs every few minutes. The DLSE also allows for added protection and control by integrating decision-making into its algorithm. This gives these devices the ability to predict fault propagation and respond to it accordingly.

The DLSE also has topology and event-detection capabilities that can inform ComEd's operators about switching events on its system in real time (see **Figure 7**). The DLSE is also the first line of defense against PMU data anomalies and drifting sensors (current or voltage) by detecting them before critical function failure. All these functionalities are essential for PMU-based applications to perform reliably on the distribution system.

FIGURE 7. The topology and event detection information flow from the DLSE.

Additional information about this figure is available in the appendix.



ComEd's program involved deploying PMUs on its distribution system over five years and included a tiered approach to diversify its installment. The utility's PMU deployment was critical in enhancing its operational efficiency and its ability to scale clean energy resource integrations, and in driving the integration of distribution automation devices to build a smarter grid. ComEd has deployed 191 PMUs as part of its distribution PMU program, with an additional 71 scheduled for completion.

Using PMUs holistically across their distribution system will reap many benefits for ComEd:

- **Greater reliability and resilience:** Mitigate issues caused by major weather or climate change events and growing cybersecurity threats
- **Monitoring power quality on feeders:** Detect voltage sags, swells, short- or long-term power flickers, rapid voltage changes, harmonics (location and direction), system dynamics, and oscillatory behavior
- **Improving stability management:** Ensure the distribution system is stable by avoiding voltage, frequency, and power fluctuations
- **Optimizing Volt-var control:** Determine the best control settings to enhance energy efficiency and power quality
- **Integrating DERs:** Provide higher visibility of DER penetration, mitigates DER protection and control challenges caused by bi-directional power flow, and identifies DER impacts to the transmission system
- **Managing advanced microgrids:** Enable quick detection of faults in a microgrid, allow ComEd to learn about islanded and grid-connected microgrid behavior and its interaction with different components, and benchmarks microgrid controller performance
- **Adopting electric vehicles:** Allow ComEd to plan for electric vehicle adoption and charging patterns or scenarios that require additional field measurements and can create operational and system planning challenges (e.g., if clouds cover a photovoltaic site when electric vehicles are charging)
- **Monitoring other assets:** Provide visibility into which assets may fail when coupled with DLSE modeling
- **Easing asset integration:** Streamline photovoltaic, battery energy storage systems, and DER integration
- **Reducing costs:** Lessen the number of PMUs needed by roughly a factor of three

THINKING TO THE FUTURE

ComEd plans to roll out more IntelliRupter fault interrupters with phasor-measurement capability to establish a highly robust analytical platform on its system. This will enable the utility to discover additional reliability benefits through the fault interrupter's phasor-measurement capability.

The electric distribution grid is undergoing transformative change to achieve clean energy goals, such as integrating more DERs into the grid. Simultaneously, the industry is modernizing the grid by adopting smart technology, automation, and microgrids.

Navigating these changes requires a greater need for widespread visibility of the distribution system. ComEd's broad deployment of IntelliRupter fault interrupters with phasor-measurement functionality allows it to have the detailed, real-time understanding of its system that it needs. Integrating a higher level of data and responsiveness into its operations by using PMUs will enable ComEd to build a reliable, resilient grid that can enable the clean energy transition.

APPENDIX

Additional Information about "Figure 1. Synchrophasor waveforms and the formula to calculate synchrophasor values," from page 2:

Line Chart

A line chart showing three cycles of a reference waveform and the corresponding measured waveform. Each waveform goes through three full cycles.

The Y axis shows voltage or current values per unit. It has a range of negative 1.2 at the bottom through positive 1.2 at the top in increments of 0.2.

The X axis shows time in milliseconds starting at 0.00 milliseconds on the left side of the X axis and going up to 50.00 milliseconds on the right side. In between the 0.00-milliseconds and 50.00-millisecond values on the X axis are 16.67 and 33.33 milliseconds.

The reference waveform has four peaks and three troughs that correspond to the start of the normal 60-Hz cycle, with peaks at 0.00, 16.67, 33.33, and 50.00 milliseconds. All four peaks have a value of 1.0. The first trough occurs halfway between 0.00 and 16.67 milliseconds. The second trough occurs halfway between 16.67 and 33.33 milliseconds. The third trough on the reference waveform occurs halfway between 33.33 and 50.00 milliseconds. All three troughs have a value of negative 1.0.

The real waveform has four peaks and three troughs and has a magnitude of about 70 percent of the reference waveform and a phase shift of about 30 degrees. The peaks occur shortly after 0.00, 16.67, 33.33, and 50.00 milliseconds. All four peaks have approximately 0.7 for their voltage or current values. The first trough occurs between 0.00 and 16.67 milliseconds. The second trough occurs between 16.67 and 33.33 milliseconds. The third trough occurs between 33.33 and 50.00 milliseconds. All three troughs have a value of approximately negative 0.7.

Formulas

Formula 1: Reactance (x) as a function of time (t) is equal to magnitude capital A multiplied by the cosine of the sum of the angular frequency omega multiplied by time (t) plus the phase offset phi.

Formula 2: Voltage (v) as a function of time (t) is equal to the magnitude of the voltage capital V multiplied by the cosine of the sum of the angular frequency omega multiplied by time (t) plus the phase offset phi.

Formula 3: Current (i) as a function of time (t) is equal to the magnitude of the current capital I multiplied by the cosine of the sum of the angular frequency omega multiplied by time (t) plus the phase offset phi.

Additional Information about "Figure 2. The connections between PMUs and PDCs on ComEd's system," from page 3:

A flow diagram showing the connections between the phasor data concentrators in ComEd's data or control centers, and the phasor measurement units within ComEd's substations and on their feeders. There are seven boxes in the flow diagram.

The top two boxes represent data or control centers, labeled A and B respectively. A red line running through each box represents the network. Both data or control center boxes have the same components in them: one main apps, one super-phasor data concentrator, one storage, and two routers and firewalls.

Both data or control centers include other applications for fault location, Volt/var optimization, and others. In each data or control center box, the main applications component, the other applications component, and the super-phasor data concentrator component are connected to the red network line. The network connection at the bottom of the data center or control center enters the box through the router and firewall. The storage is connected to the super-phasor data concentrator. A separate edge router and firewall connect the network to other users, such as the transmission system. A dotted line between the edge router and the solid red network line indicates that the network connection to other users is optional.

The data centers or control centers connect to devices out in the field. This is represented in the drawing by a continuation of the red network line. A cloud icon indicates the network transmission can use various media.

One of the field devices shown is a substation with a local phasor data concentrator and a single communication path. This is shown in the lower left of the figure. There is a router and firewall at the network connection to the substation. The network then continues into a switch and onto the substation LAN. The phasor data concentrator connects to the LAN, as do two phasor measurement units labeled "PMU 111" and "PMU 112." There is a data-storage device connected directly to the phasor data concentrator.

Another of the field devices is a small substation located to the right of the first substation. There is a router and firewall at the network connection to the substation. The network then continues into a switch and onto the substation LAN. Two phasor-measurement units connect to the LAN. These are labeled "PMU 201" and "PMU 202."

Another field device is a substation with an aggregating phasor data collector. This is shown to the right of the second substation. There is a router and firewall at the network connection to the substation. The substation has a phasor data collector labeled "PDC 1" that connects to the LAN and a phasor-measurement unit labeled "PMU 301" that connects to the LAN. A storage device connects directly to the phasor data collector. There is a second phasor data collector at the same location as the router and firewall labeled "PDC 2," and a note indicates that this is "for feeder PMUs."

Another field device is a feeder on the right side of the diagram that has two phasor-measurement units labeled "PMU 33" and "PMU 34." These are connected to a switch that in turn connects by fiber to a gateway next to the third substation. A storage device connects directly to the phasor data collector PMU 34.

Another field device is a feeder on the right side of the diagram that has two phasor-measurement units labeled "PMU 31" and "PMU 32." These are connected to a wireless connection and firewall that in turn connects by radio to the same gateway next to the third substation.

All connections in the diagram have text indicating they support transfer rates of 60 phasors per second, except the connections within the two on-feeder boxes. The connections within the two feeder boxes show rates of 1 to 60 phasors per second.

Additional Information about "Figure 4. A topology of the micro-PMU network in the GrIT lab," from page 7:

A box labeled "Control Omicron Parameters Test" is connected to a box labeled "Test Set." The test set is connected to a micro-phasor-measurement unit. The phasor-measurement unit is connected to a switch. The switch is connected to two personal computers and a phasor data concentrator.

Additional Information about "Figure 6. A typical data flow path for Field PMU communications," from page 8:

The data flow is top to bottom. At the top is the analog measurement. The data from the current transformer and potential transformer circuits go to a phasor-measurement unit. A communication link brings the data from the phasor measurement unit to a local phasor data concentrator. Another communication link brings the data from the local phasor data concentrator to a regional phasor data concentrator. Another communication link brings data from the regional phasor data concentrator to the control center. Phasor applications are then implemented at the control center.

Additional Information about "Figure 7. The topology and event detection information flow from the DLSE," from page 9:

At the left is a box labeled "Linear State Estimation" that includes the functions observability analysis and bad-data detection and conditioning. The linear state estimation information is then passed to a box labeled "Advanced Applications." The advanced applications include contingency analysis, voltage-stability analysis, automatic corrective actions, phase-angle limit computation, and analysis of cascading outages. The advanced applications information is then passed into a box labeled "Visualization and Alarming." This stage has the functions of visualization and trending of limits and critical contingencies/cascades, alarming on voltage- and transient-stability limits, and phase-angle limits and critical contingencies/cascades occurrences.

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