NASPI North American SynchroPhasor Initiative

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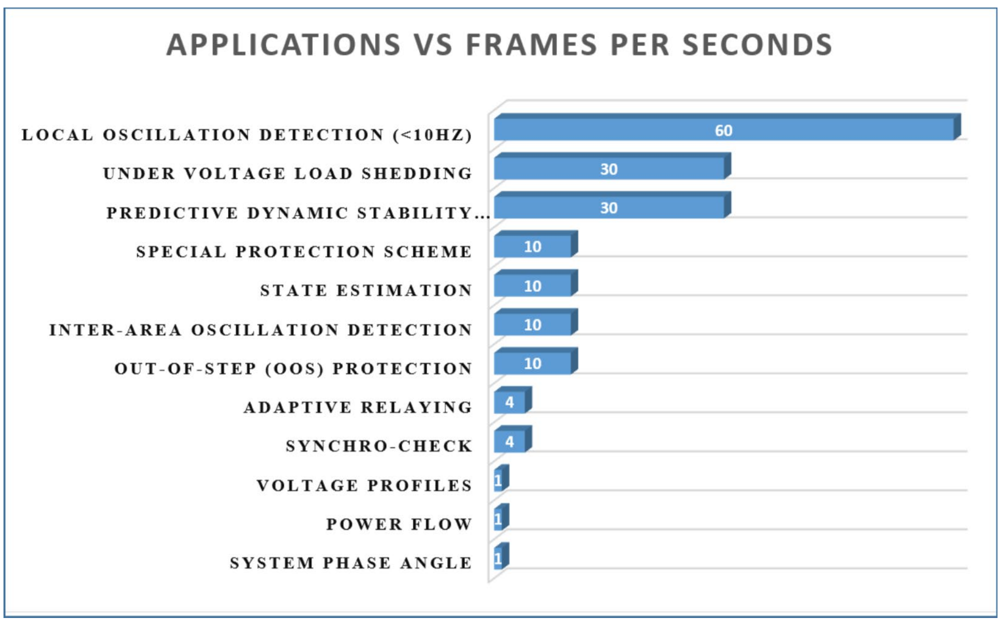
Webinar Questions and Answers

"Synchronized Measurements in Distribution Systems"

with Paul Pabst and Kevin Chen

Is there any reason for 60 Hz phasor output (compared to 10 or 120 Hz)?

PMUs and DLSE can operate at other Phasor outputs as well. It has been an industry practice to run PMUs at 60 or 30 frames per seconds. Our Field PMUs are set at 60 Frames per seconds. There are several studies showing the PMU reporting rate vs the applications they can support.



How do you overcome the (complete) observability requirement for PMU-based state estimation?

We have developed the DLSE solution for our Bronzeville Community Microgrid. There were several rounds of observability studies that was conducted. We had to re-adjust the PMU placement based on the actual field conditions. For example, at locations where PMUs cannot be physically installed were marked unavailable and the observability analysis were re-run and new PMU placement locations were obtained.

As for the condition monitoring using PMU data, can you elaborate more? Are we using PMU data to monitor the overhead lines (such as arcing, broken conductor, fault location, etc..)?

PMU data is stored in a central repository and timestamped. There are many use cases of this data, one of those being event analysis. ComEd is actively using PMU data for post event-analysis (arcing, faults, etc.)

How do you integrate time-synchronized PMU measurements with non-time-synchronized SCADA and smart meter measurements for reliable decision-making?

We are currently only using PMUs to perform Linear State Estimation. We are not using the SCADA and other measurements, but it is in our future plans.

How are you going to synchronize the PMU's down the feeders in a secure manner?

The PMUs are GPS synchronized locally using a GPS clock.

When deploying PMUs, how do you generally select their optimal locations?

We perform Observability Analysis studies to ensure complete situational awareness. We also consider different topologies that a circuit can operate and re-run the observability analysis to ensure situational awareness in different topologies.

How would you compare the costs for transmission- and distribution-level PMUs? Thanks.

The costs are reasonably similar but very site-specific. ComEd is targeting the right balance of cost vs. impact on its PMU deployment, and certain associated costs include upgrading of protective relaying, upgrading/installing/replacing sensing equipment, expansion of time-synchronization capabilities, etc. Careful considerations must be considered when these upgrades are to be scheduled, and transmission upgrades typically require more coordination than distribution upgrades.

What do we mean by "feeder mainstream PMU"? Do we mean integrate PMU functions into DA devices such reclosers? How could it be done, technically?

This refers to PMU's outside of the substation. Also call distribution feeder PMU's. These would first include existing infrastructure like reclosers and associated relaying. In the ideal case PMU functionality is added to the existing relaying at the recloser and leverages the existing voltage/current sensing. In some cases, these upgrades are not feasible and stand-alone PMU's are added which include all the above plus more. Generally, it is less expensive to upgrade a feeder mainstream PMU as opposed to installing a standalone PMU.

Can the SEL-3573 to detect which version is used by the PMU and use the appropriate version 2005 or 2011 to use?

The SEL-3573 supports both versions of the C37.118 standard. More details on the specifics of how the 3573 handles the different standards can be found in the SEL product manual.

Can you think of some distribution system applications that cannot be done if time-synchronized measurements are not available in the distribution system?

Event Detection, localization cannot be done in certain cases with the non-time-stamped SCADA measurements.

Any concerns on having the protection functions and PMU functions on the same device (relay)?

PMUs will be a monitoring device that will not be involved with the protection function at the relay. We don’t see any concerns.

Do you use IEC61850-SampledValues or some other protocol for transmitting PMU data?

We use C37.118.2 Protocol.

Why servicing / replacing a substation relay requires an outage? Can't load be transferred to adjacent feeders / substations?

This is site-specific and varies. Normally yes, load can be transferred to adjacent feeders but there are likely going to be scenarios where the PMU is installed on a radial line without an alternate feed. Outages are avoided and the preference is to offload the customer load to an alternate feed.

Are you using single mode or multi-mode fiber optic cabling?

There is no technical preference for PMU data, as both single mode and multi-mode support the necessary bandwidth. The choice of multi-mode or single mode is site-specific and varies depending on distance, standards, preferences, etc.

In slide 15, it shows wireless as an option to transport data. Can you elaborate what kind of wireless technology is used? Does it have enough bandwidth?

Wireless transmission is still being studied. Currently all deployed PMU’s are communicating over a hard-wired connection.

Having a fiber network is somewhat of a luxury. Can this work with cellular-ethernet comms at field devices, or is there too much communications lag?

PMUs do require a fast and reliable communication. The infrastructure cost is high. In theory it may work, but scalability will be an issue.

What is the difference between a PMU and a microPMU?

MicroPMU is a specific device name that is designed to have PMU functions for the distribution level.

Any major challenges with getting the RTDS system set up to provide synchrophasor data?

No.

Do the D-LSE have digital inputs to get breaker positions and actual PMUs provide such digital data?

Yes.

Are you looking at enabling access to the data to troubleshooters/field personnel? if so, what tools are you planning to use for that?

Not the actual data, but our situational awareness tool (DLSE) can streamline the trouble shooting process.

For fault anticipation would be useful to have the high frequency content of the V & I in the grid. How much HF content is present in these PMU measurements?

PMUs only measure the fundamental frequency. They filter out all other frequencies.

In testing the DLSE with RTDS, are you injecting harmonics and other sources of noise that are present on the distribution network, especially when inverter-based generators are connected? If yes, what is the THD?

No, all the natural noise that comes from the RTDS model. We also include bad data such as outliers and missing data.

Have you identified any event profiles (animal contact, intermittent tree contact, arcing switches, etc.) based on the data collected to date? Any plans to create an event library for the real time operations group?

That is a great idea. Yes, our PMUs have recoded incidents on our circuits. One recent example was a bunch balloons touching the 12kV line and causing outage.

How is observability improved using PMU accuracy compared to using phasors which are either synchronized within 1 ms or which have an accuracy of 2% rather than a TVE of <1%? What does the improvement allow to be done that couldn't be done before?

Observability should remain the same if the device is timestamped but has a lower accuracy, However, the accuracy of the situational awareness will not be same when we compare two devices that has 1% TVE vs a device with higher TVE.

Did you have a driver to start collecting at 60 samples per second? Was 30 samples/second "too slow" for the applications you were developing?

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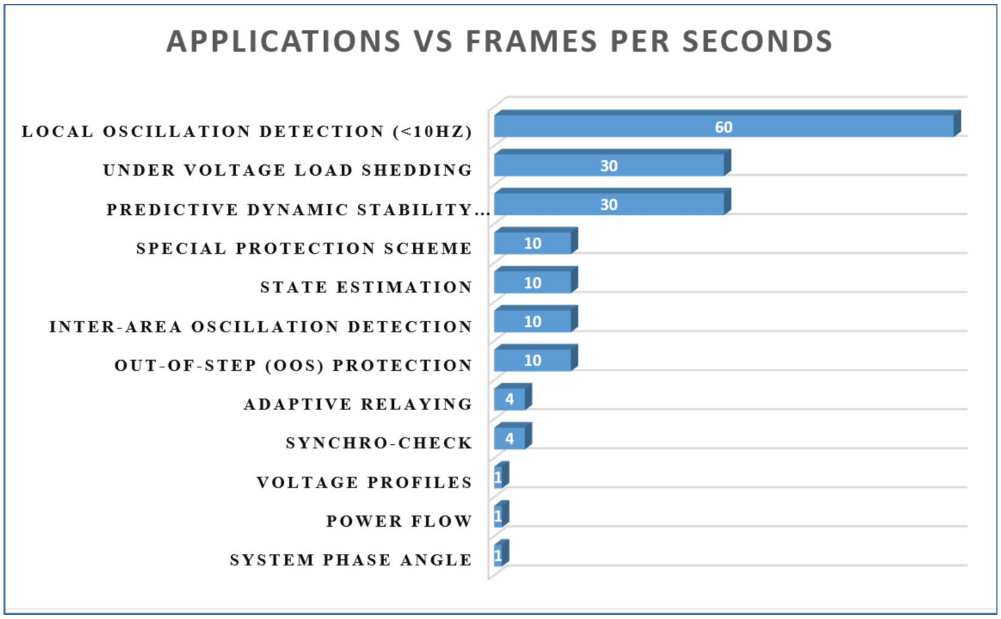

The PMU data heavily relies on communication. It will work well in the labs. But when deployed in the field, what communication we are using? Do we see the data loss or significant delay?

Our PMUs are on fiber network.

Does ComEd have plans to extend PMU-like monitoring and analytics into the DC-side of microgrids, renewables, or PJM/ MISO HVDC links? Or AC-side only on the 12kV and 34kV lines?

No plans yet.

Do you see some value(s) in doing dynamic state estimation vs. static state estimation for the distribution system?

Yes, with more DERs a dynamic state estimator will be helpful.

Have you considered the effects of unbalanced loading in the microgrid studies? I guess a follow-up would be how unbalanced do you expect the ugrid to be in practice?

Our lab model has unbalance and we are considering unbalance in all our studies.

In terms of topology changes, can you really see find out the on/off state of ALL the circuit breakers etc.? Have you performed any sensitivity analysis in that respect?

Yes, we can. There are limitations if we have bad PMU measurements and redundancy and observability is compromised.

How do you say that PMU data is bad?

When there is a missing data or an outlier. We have developed algorithms to detect the bas data. We have injected synthetic bad data and have trained the software to detect them.

Where can I find the standard for a microPMU?

MicroPMus or Distribution PMUs have no standard.

Have you identified any voltage oscillations on the distribution system driven from transmission system connected non-conforming loads?

No.

In one of the earlier slides, it says that the PMU data is sent to the substation PMU, control center PMU and a synchrophasor management system. How does the PMU send data to all three destinations?

PDC can send data to multiple clients.

Please comment if the existing 118-1 std served well. My question is because the existing std was written around transmission systems, not distribution.

Yes, it did.

I would like to know what makes a microPMU different from a PMU?

In essence they are same. MicroPMUs are designed for the distribution system and are a proprietary device of a specific vendor. It is hard to comment on their estimation algorithm.

Have you seen voltage increases beyond your regulated limit on feeders with heavy inverter-based resources?

This information is not known by the PMU team.

How far is typical distance between PT & CT sensors and PMU? Is there any signal transmission delay or attenuation? Basically, my question is the sensor accuracy, assuming PMU is quite accurate and does a good job.

Sensor accuracy is very important and secondary cabling distance plays a vital role in maintaining accuracies stay within acceptable limits. In a substation environment the cabling is likely coming from the substation yard and into the control house, landing on the protective relay. These signals are used for protection, control, and PMU data, and cabling varies from 10s of feet to a few hundred feet. The distribution feeder PMU PT/CT devices are pole mounted and the PMU's are usually on the same pole, so secondary cabling is less than 50 feet.

how do you reduce the voltage in those situations?

We are not following the context.

Are there any taps at buses that are not observable between PMU? How do these taps affect accuracy of estimates?

Yes, they are. The non-observable area is taken out of the study.

How are you able to locate the fault location (is it impedance based) on the RTDS system you showed?

ComEd is working on identifying high impedance fault location algorithm.

Can you provide details about the radio communication channels that are used?

We are not following the context, but wireless/radio communication is still being studied as a potential medium for PMU transmission.

There are 100s of papers in IEEE Xplore which refer to "microPMUs" as though they are a class of instrument, rather than that they are a brand name for Power side's PMU product.

How can we address this confusion?

Stop using the term MicroPMU. People are not aware of this fact.

Any thoughts on what is beyond PMU? How to capture actionable data that is not within the fundamental frequency?

Harmonic Synchrophasor.

How does microPMU on feeder receives time-of-day information from GPS? Does it have GPS receiver/antenna?

Yes.

A large amount of PMU data is measured. how is that transmitted over radio that has likely a much lower bandwidth. Using compression or selective transmission (or both)?

We don't use Radio. We use Fiber.

On next steps - can you elaborate more on pre-event detection with point-on-wave data? What technology do you use and how do you use PMU data for it?

The team is building a distribution linear state estimator that leverages PMU data to predict future states of the power system. This model could potentially provide insights into detecting events/transients as they are developing, allowing operators advanced notification

We have a challenging time just getting steady-state voltage data from all our feeders simply due to cost of metering equipment and communications infrastructure (especially for remote areas). What was the main business driver used to justify the expense for a Distribution PMU system? It strikes me as being very expensive for the potential payoff.

Innovation and Technology is always expensive.

You may have addressed already, but what are the latency requirements?

PMU team will follow up on this one separately.