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PNNL-30757

Advanced Power Systems Measurements

A Literature Review

December 2020

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U.S. DEPARTMENT OF ENERGY

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Abstract

In 2020, a literature survey was performed as part of a project aimed at producing guidance for the Department of Energy in the form of a Roadmap. The topic of the Roadmap was *measurement*. That was viewed as being generally underrepresented in consideration of *sensing and measurement* or *instrumentation and measurement.* Sensing is just the beginning of a process, and the instrument is just the container for the process. Measurement, the experimental process, has acquired a considerable body of theory over the last few decades, theory that is not widely taught and disseminated.

The results of the survey can be said broadly to reflect that lack of appreciation.

Specifically, the review found that there is support for the development of a more “capable” PMU. New algorithms and new documentary standards will be needed. Some of the findings are:

- Point-on-wave technology adds new capability to the existing suite of measurements, and could allow for improved operation and protection
- Power quality analysis has historically been concerned with assessment of how non-sinusoidal the delivered voltage shows promise in signature recognition, a departure from the modeling that has historically characterized power system measurements.
- The PMU is assessed as being a remarkable measurement system, but its performance is held back by the lack of understanding of the measurement theory underpinning its operation.
- The PMU is being considered for application in the distribution system. There is a danger that it will be seen only in the light of the successful PMU implementation in transmission, and the two have different requirements.

These various expansions of measurements will no doubt benefit from a better appreciation of the theoretical aspects of measurement. In this, and other, regards, our survey of the literature has identified gaps as well as possibilities.

Acknowledgments

The work described in this report could not have been completed without the contributions of a large number of people. Sandra Jenkins, of the Office of Energy of the United States Department of Energy, and Dr. Guohui Yuan, of the Department of Energy's Solar Energy Technologies Office deserve special mention. Their continuing involvement, guidance and support helped us maintain momentum.

The authors would also like to thank Dr. Rod White, late of the Measurement Standards Laboratory of New Zealand for many fruitful discussions, Professor Dani Strickland of Loughborough University in the UK for her insights in numerous discussion, and Dr. David Laverty of the Queen's University, Belfast, Ireland for his many contributions to the work on phasor measurement units.

Acronyms and Abbreviations

AGC	Automatic generation controller
CIP	Critical Infrastructure Protection (NERC standard)
DER	Distributed energy resource
EERE	Office of Energy Efficiency and Renewable Energy
EPRI	Electric Power Research Institute
GMLC	Grid Modernization Lab Consortium
GNNS	Global navigation satellite system
GPS	Global positioning system
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent system operator
NASPI	North American Synchrophasor Initiative
NERC	North American Electricity Reliability Corporation
ORNL	Oak Ridge National Laboratory
OE	Office of Electricity
PMU	Phasor measurement unit
PNNL	Pacific Northwest National Laboratory
PV	Photovoltaic
RMS	Root-mean squared
ROCOF	Rate of change of frequency
SCADA	Supervisory control and data acquisition
SDN	Software-defined network
THD	Total harmonic distortion

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1.0 Introduction

1.1 Background

In late 2019, a small team at the Pacific Northwest National Laboratory (PNNL) began a project for the US Department of Energy on the topic of measurement. While the human species has been making measurements for thousands of years, a theoretical underpinning of the process has been lacking for most of that time. The views that are most widely accepted now have been forming for only the last few decades. It follows that most of the measurements made today in the electric power system have been developed from concepts that originated before the modern understanding had formed.

The origins of modern electrical measurement can probably be traced back no further than 1873, the year that Maxwell published his Treatise on Electricity and Magnetism. Advances were made late in the 19th century when some instruments were made direct-reading. In the second half of the 20th century, some of these instruments were converted to digital form. A major advance in power system measurement capability took place toward the end of the 20th century, when the PMU was invented and commercialized.

But the advances in measurement theory that had been taking place in parallel did not impact any of the advances in instrumentation. As evidence of that, consider that in August 2016 almost a GW of solar PV generation relayed out because of a protection operation that should not have occurred. The cause of the false trip was a bad measurement. That is to say, there was no defect in the installation or the instrument. The problem was in a measurement of something known as frequency. The measurement method was based on some invalid assumptions: theoretical aspects of the measurement were simply incorrect.

This event, associated with the Blue Cut fire in Southern California, was found to represent one of many similar events. Some of the PNNL team had already developed a PMU that suggested a solution the problem. They had also identified problems with the measurement of reactive power—problems that can be traced back to early in the 20th century.

The PNNL project on measurement was charged with investigating the field and producing a report to give guidance to the DOE.

This Literature Survey was performed as part of an introductory phase of the project. At the request of the DOE, it is being published in advance of the final report. What follows has been edited only for consistency of internal reference.

1.2 The Literature Survey

Though the authors of this report could be regarded as having their fingers on the pulse of many of the technology developments now under way, it is reasonable to think that they do not know quite everything that is going on. A literature survey of the relevant fields was viewed as being in order. Earlier discussion with DOE had led to *advanced measurement* being considered the overall subject, in particular the following aspects:

- Information
- Technology

- Applications of Theory
- Policy
- Standards

The relevant literature, particularly the literature available in IEEE, was examined by various team members. It was found to be rich with information about existing measurement systems and their applications. An overview of these findings is provided in this chapter.

This chapter also discusses original findings based on the team's interactions with utilities, vendors, researchers, and other stakeholders. Many of these interactions took place during a set of three webinars hosted by the research team. These webinars were designed to help the team gain insights that are valuable but typically unavailable in the published literature. Through the webinars, the team was able to hear directly from over 30 participants. The webinars included presentations by the PNNL team, open discussion, and a live survey[1] where participants submitted answers to specific questions. Notes from the discussions and results from the surveys can be found throughout the following sections. A complete list of the questions posed during the webinars is provided in Appendix A.

The literature survey presented in the following sections covers an array of topics to include mature and emerging measurement technologies, related fields such as communication, and applications. To begin, an analysis of the literature on measurement in general is provided based on its metadata, rather than its technical content.

[1] Menti (or Mentimeter) is an on-line based live polling platform that was chosen for live interaction with the audience during webinar sessions. www.mentimeter.com

2.0 Literature Survey Results

2.1 Background and Metadata for Measurement in the Literature Survey Results

2.1.1 Basic findings

After the “warm up” question, a series of five questions was asked with the intent of finding out what the participants viewed as important in their work on measurements, whatever that work might be. The participants were told that there were no right or wrong answers to the questions, and this was not to be viewed as a test. The questions had the aim of finding out something about the participants. As far as seemed reasonable, the responses would be taken as representative of the power community in general.

The first question was How do you know when you have made a good measurement, one that you can trust? As a specialist in measurement, one might have the attitude that one did not really trust the results of any measurement, or at least not beyond the point indicated by its uncertainty statement. But for many users of measurement results, there are certain aspects of the process that encourage acceptance of the results. The choices that were offered (and the number of votes given by the participants) were:

Table 1 Reasons to trust a measurement result

Option	Total votes
The instrument is from a reputable manufacturer	4
The calibration sticker is current	3
The results fit your expectations (pass your sanity check)	14
Other	10

21 participants responded to the question. The *manufacturer* was regarded as relevant by four, the *calibration sticker* by three, and fourteen respondents put some faith in their *sanity check*. Ten respondents thought there were *other* factors that we had not listed. (Of course, it is almost inevitable that a finite list is incomplete. “All of the above” would be an option, too!)

It is possible to draw some conclusions from these results, though some must be considered tentative.

- The relatively low importance attached to the manufacturer factor may be a result of the uniformly high quality of most measurement products. The relevance of good documentary standards (an example from the other category) was mentioned by a participant in the “chat” window as being a factor in assuring good results.
- The question on calibration stickers is a sort of reverse question. An up-to-date sticker may not mean a good result, but an out of date sticker must imply that one can have only low confidence in the result.

In fact, the calibration sticker should be regarded as crucial, and we will look further at that shortly. The very low score for the calibration sticker choice supports the conclusion that a bureaucracy separate from the user community is needed in most companies to enforce the currency of such stickers.

All measurement instruments have a factor that is akin to the familiar MTBF (mean time between failures) for hardware. For a measuring instrument, “failure” means “out of tolerance,” and not just failure to work. The factor MTBOOT (mean time between out of tolerance) is a statistical guide to setting a calibration interval for the instrument. With the advent of digital instruments, the MTBOOT has generally increased from the days of analog measurements, if for no other reason than that there are fewer elements of the system whose values can drift. One may imagine that the digital part of the system either works or does not work, but the analog part of the instrument may be subject to drift. Such drift is a feature of the passive components in the front-end of digital instruments.

The MTBOOT is, of course, dependent on the tolerance allowed in the measurement. A resistive divider may drift by (say) 0.01% in one year, but the same divider might take as few as five years or as many as twenty to drift by 0.1%. Some capacitive dividers used as instrument transformers (and external to the instrument itself) are known to sometimes drift orders of magnitude more than this.

- The sanity check is viewed as relevant and important. A future problem with reliance on such a check is that it is mostly left to the human part of the measurement chain to apply the check. As the power system evolves toward greater automation, it must surely benefit from a greater amount of automated sanity checking. Another comment from the “chat” window was that this would be a good problem in which to engage the AI community.

The next question was *Would it be a help to have a believability metric associated to reported measurement values?* This question required the participant to give their own estimate of value, on a scale from one to ten. The results from the fifteen respondents are shown:

Table 2 Worthwhileness of a measurement trust metric

Metric importance	1	2	3	4	5	6	7	8	9	10
Score (scale of 10)	1		2	3	2		3		2	3

It would seem that people do not have a sense that a metric is needed, or perhaps they do not know what it is or how it would work. This attitude is in strong contrast to the views of the BIPM, which states that a statement of uncertainty is *obligatory*. Here is what the GUM (Joint Committee for Guides in Metrology, WG 1, 2008) says in the first paragraph of the Introduction:

> When reporting the result of a measurement of a physical quantity, it is obligatory that some quantitative indication of the quality of the result be given so that those who use it can assess its reliability. Without such an indication, measurement results cannot be compared, either among themselves or with reference values given in a specification or standard. It is therefore necessary that there be a readily implemented, easily understood, and generally accepted procedure for characterizing the quality of a result of a measurement, that is, for evaluating and expressing its uncertainty.

Power engineers in general are accustomed to having no statement of uncertainty in association with the results of measurements in the power system. It seems very likely that the prevailing sentiment is caused by “what you don’t see, you don’t miss.” The lack of such a metric is inevitable if the measurement process is purely operational, and that means that it is not possible to provide such a metric in any conventional way for the measurement of (for example) reactive power.[1]

The third question of the series was How many definitions are you aware of for power factor? The question was answered by 15 participants, as follows:

Table 3 Number of definitions of Power Factor

Power Factor Definitions	1	2	3	4	5	6	7	8	9	10
Number of respondents	1	2	0	0	1	1	2	6	0	2

It is strange that there really are multiple definitions for power factor. The question does not require that the participant indicate that he or she knows any of the definitions, it probes the participants’ awareness. Nevertheless, one respondent did identify two definitions by name in the “chat” window. It seems that not everyone is aware that there are actually very many definitions, though the majority do seem to know that there is more than one.

The fact that a few participants are not aware of more than one or two definitions suggests an unjustified level of confidence.

The fourth question in the series was *Does reactive power always involve stored energy?* 13 respondents thought it did, 7 thought it did not.

These responses show that while power engineers write a great deal about reactive power[2] and rely on measured results during system operation and planning, the concept is not well thought-out. Because of that it must be impossible to teach coherently.

For this question, the three different days of the Webinar yielded some possible hints of peer pressure. The totals were, by day, 7-2, 1-5, 5-0. There is no right answer in the sense that the purpose of the question is to find out about the respondent: but the reader of this report may have a deep concern because of the spread of results among the respondents.

It should not be taken as a reflection on the quality of the respondents that such an important measurand is so poorly thought out. That is a problem whose origins so ancient that it seems fair to describe modern views as fossils. The experts and thought-leaders of our profession studied the matter in its early days, and failed to recognize the nature of the problem *because*

[1] The measurement of power is also purely operational, but the calculation involved (the arithmetic average of the sampled values) is not dependent on details of the waveshape of the voltage or current signals provided the samples are simultaneous and the waves are periodic, and the measurement is performed over an interval that is an integral number of the periods of the lowest common period of the two waves. The accuracy of the measurement of power is limited, within the instrument itself, only by the quality of analog parts of the front-end, the A/D converters, and their timing circuitry.

[2] The expression “reactive power” appeared in the metadata of more than 2,200 conference papers and more than 800 journal papers in 2019, the last full year for which IEEEXplore data are available.

there was then no underlying measurement theory to provide guidance. The community of power engineers has continued to lack clarity on this topic for a century *because the education process has become siloed*. Power engineers have not been required to learn about measurement since measurement theory reached a point that it could have illuminated the matter. People who are involved in the fundamentals of measurement have not been greatly concerned with power system measurements.

The final question of the series included a little background about the education process for power engineers. The participants' screens showed the question this way: *It is taught in school that the power, reactive power and apparent power form a right-angle triangle. How true is that?*

Three choices were offered: *never true*; *sometimes true*, *always true*.

No respondent voted for *never true*. That must be regarded as slightly surprising, since if the question had been asked as part of a test, that would be the right answer. Given that the waveforms of the power system are always at least slightly distorted, the right-triangle is never possible. The votes were 17 in favor of "sometimes true," and three in favor of "always true." Some level of concern should be triggered by the three responses that thought "always true" was an acceptable answer. That is evidence of a belief in the reality of a world that is imaginary and idealized.

2.1.2 Overall Comment, Webinar broad questions

The responses to the questions give some insight into the attitudes and ideas current in community of the users of measurement results. With a sample size of around 20, the insight cannot be taken as surely representative, but it is at least suggestive.

The idea that measurement systems can drift out of calibration should be taught to the user community. The power engineering community might expect long life for its equipment, but mere failure to catch fire is not a sure indicator of an accurate measurement.

A *sanity check* as a way of assessing the quality of a result is perfectly reasonable, and it was the favorite among our respondents. It may be that it has been favored because there has been no alternative, since uncertainty statements are not used in the domain of the power system. A sanity check is based on a model of the system being measured, whether that model is a mental one or a mathematical one. One of the participants pointed out in the "chat" window, it is not possible to "do a sanity check on each measurement, you have to take them as a group. It's a whole system aspect because it can fail at so many different points." Another participant pointed out that it would be "worth talking to people in AI about sanity checks, they're very good at it." There is clear support here for increasing confidence by taking advantage of work in other fields for the sanity check.

A single-measurement believability metric has been proposed by PNNL, and some of the participants were aware of that. One brought up the topic on the "chat" window. Another participant offered the comment that "Believability parameter – very similar to the degree of confidence the intelligence community gives in briefings. In recent hearings Congress has asked them how confident they are in their degree of confidence. Something to think about." This view is an echo of the PNNL view that "uncertainty" in the way it is defined and estimated today, is not a useful metric in the domain of the power system. When a new "believability metric" is developed, it should be supported by evidence of its own credibility. The proposed believability metric is not the same thing as the tried-and-true uncertainty statement, and introducing it might be viewed as facing a challenge similar to the one faced when LED lighting started to indicate the lumen output instead of the power input.

It is also beyond doubt that the topics examined by the last three questions, reactive power, power factor, and the power triangle, are muddled concepts. A major revision of what is taught to aspiring power engineers is called for.[1] The problems suggested by the webinar are consistent with the findings of the literature survey

2.2 Literature Survey

The IEEE database IEEEXplore returns nearly 15,000 hits for publications containing the word "power" in the name of the publication, just for the year 2019, the most recent complete year in the database. Earlier years have similar numbers. An up-front aspect of the search done for this survey was clearly to reduce the number of papers that we considered.

To find aspects of these thousands of publications that would be relevant to the matter of providing guidance to the US DOE in the form of a roadmap, we were guided by our own experience, and also by what other authors have considered to be important in terms of implementing advanced measurement in the smart grid, and dealing with the changing milieu of power generation and delivery. First, we consider how the overall field was narrowed.

2.2.1 Top-level topics

A number of things on which a somewhat focused search into related measurements could be based can be discerned from considerations of the large-scale influences, and experience in the overall field. We must consider what controllability and observability mean with respect to:

- Increased dependence on wind, solar and hydro generation
    - Some of this will be at the scale of the transmission system, some in distribution
- Increased involvement of EVs in system operation both as storage and controllable load
- Increased use of energy storage of several kinds

2.2.2 Second-level topics

From these overarching factors the need for advanced measurement technology can be viewed as supporting a wide range of power equipment. Some of the measurement results may be required for power system resilience, and doubtless some will reflect new ways of operating. For example, there will be a higher fraction of energy from sources that have no inertia. It is reasonable to think that the "natural frequencies" that we observe when we disturb the balance of the system will increase. That may require instruments that can respond faster than is today possible.

In general, it may be expected that the system dynamics will change considerably. Some thought is being given to the use of inverter-based resources as a way to produce "synthetic inertia." The measurement challenges associated with that are daunting. Several workers have seemingly "stubbed their toes" on this measurement problem, as will be seen below. Other ways to address the "inertia deficit" include the addition of synchronous condensers to the power system. These are over-excited alternators that are operated without the expectation of

[1] A foundation for such teaching has been generated as part of the work towards revising IEEE Std 1459.

generating power. The technology is not new, and such devices have mostly been supplanted in the modern power system by static var compensators (SVCs) which accomplish much the same ends without involving moving parts. However, SVC do not add inertia to the system, and as rotating machines are replaced by inverter-based resources, the addition of inertia by this means is worthy of consideration.[1] Without mechanical inertia, the technology must rely on a measurement of *rate of change of frequency.*

The increased involvement of EVs in the load and generation mix will demand increased *communications.* For some power engineers, the thought of a communications system immediately brings to mind considerations of data rate, perhaps because of the great increases in the capability in terms of this parameter made available recently by various new technologies. The application for communications in connection with EVs will not all have to do only with high-speed communications, however. Other aspects of communications will be important. Both billing and command and control will likely be relevant, if EVs are to have maximum benefit to their owners and the local utility. That means that security and mobility are factors.

2.2.3 Results: Metadata analysis

For the calendar year 2019, the latest complete year as these words are written, a total of 2881 results are available with the words power system (without quote marks) in the title. This number reduces considerably, to 98, when the filter word “measurement” is required to be in the author keywords. It appears that relatively few authors (3.4%) considered that the word was an important enough aspect of the paper to use as an available search term.

Of these 98 papers or reports, 37 had the words “phasor measurement” in the author keywords, 13 had “frequency” there, and only two had either “rate of change” or “inertia.” Figure 1 shows these results graphically.

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[1] The reader may wonder how this works. It is well known that the power system exhibits certain “modes,” frequencies at which one part of the system “swings” against another when disturbed. In the steady state, such modes are dormant things, and it is not until the power system is “kicked” by some kind of disturbance that the modes become evident. Usually (and preferably) a mode appears as a damped oscillation of the angle between one part of the power system and another. Eventually, the various generators reach a steady operating condition. It is fair to wonder how the rotating machine “knows” what angle is appropriate, and what takes place during a transient disturbance.

The answer is that for a generator, with a driven shaft, energy is transmitted along the shaft from the prime mover to the rotor, and is extracted through the rotating field of the stator windings. During a disturbance, additional energy is extracted from the momentum of the rotating mass of the rotor and the shaft and the turbine, and returned there as the “swing” takes place.

The steady operating point of the machine, which is found by the physics of the magnetic field of the machine and is not a matter of any control system action, corresponds to having the rotor of the machine located at a minimum in the energy in the air-gap field between the rotor and the stator.

It will be noted that the rotating mass of a generator of some particular rating is greater than that of a synchronous condenser of the same rating, because only the former includes the rotating mass of the shaft and the turbine. If a generator is re-purposed for operation as a synchronous condenser, these parts may be left attached, and the inertia thereby increased. There are instances of this kind of conversion today, and its implications for the future are worth tracking.

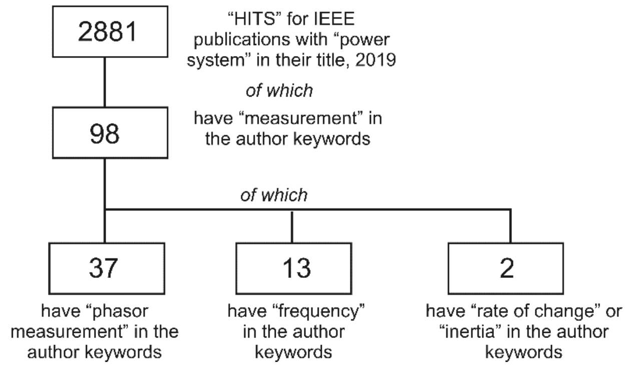

Figure 1 Breakdown of IEEEXplore *power system* results for 2019

It is not difficult to infer that measurement in general is a field of interest to very few of the people writing on the topic of power. There is a suggestion of a level of confidence in measured results that the authors of this present report consider unjustified. That topic will be considered later.

Another reason for the small number of papers on measurement may be that the field of measurement is small compared to the field of electric power. To see whether that is a factor, we performed a search in what might be called the complementary direction.

A search in the same IEEE database for the same year reveals that there are 2,341 hits for publications with the word "measurement" in their title. That is about 80% of the number of power publications. Of these, a surprisingly large number are concerned with power: 151 have the word in their author keywords. That is, 6.5% of the measurement authors consider power to be a major consideration of their work.

However, when the filter is changed to "power system," the number reduces to 48, about 2% of the total. (Examination shows the others are measuring, for example, optical power or RF power or some such thing.) Of these 48 or 49, 18 included the words "phasor measurement", 31 included the word "frequency" and 6 included "rate of change" in their author keywords. These results are shown graphically in Figure 2.

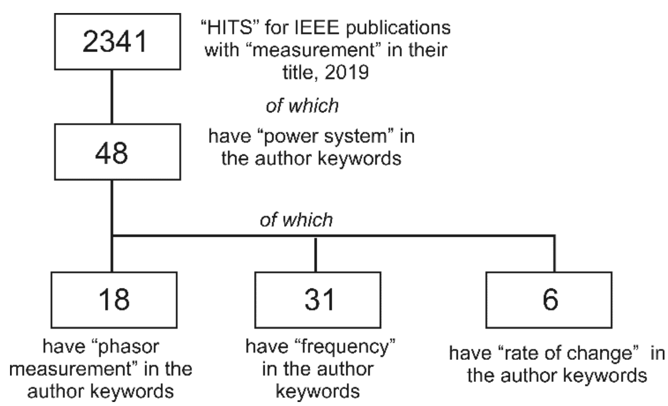

Figure 2 Breakdown of IEEEXplore *measuremeant* results for 2019

It will be seen from the diagrams that for people writing for a power audience, phasor measurement is a dominant topic, whereas for people writing for a measurement audience, albeit one interested in power systems, frequency is of more concern. It is no surprise to find that the six papers about "rate of change" are included in the 31 papers that involve "frequency."

When the quantity of papers has been reduced to this small a number, identifying some authors is unavoidable in the search, as the authors' names are displayed on the results screen. An additional factor of interest then becomes evident. Not only do the same names appear multiple times, but it becomes evident that surprisingly few are associated with US institutions. Figure 3 shows the breakdown by country for the affiliation of the first author of the papers

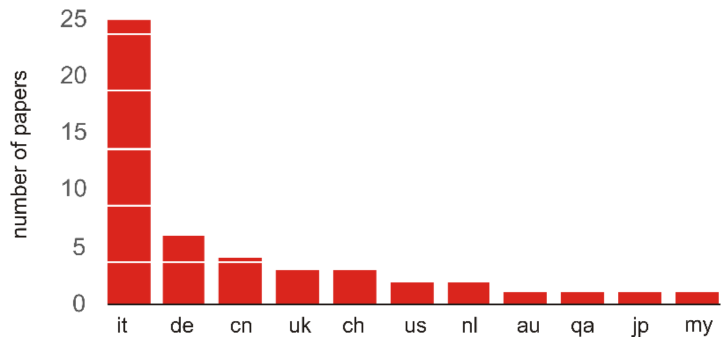

Figure 3 Number of IEEE papers with "measurement" in the Publication Title, 2019

A similar search was done for IEEE papers published in 2019 with the words "power system" in the title of the publication. Figure 4 shows the results.

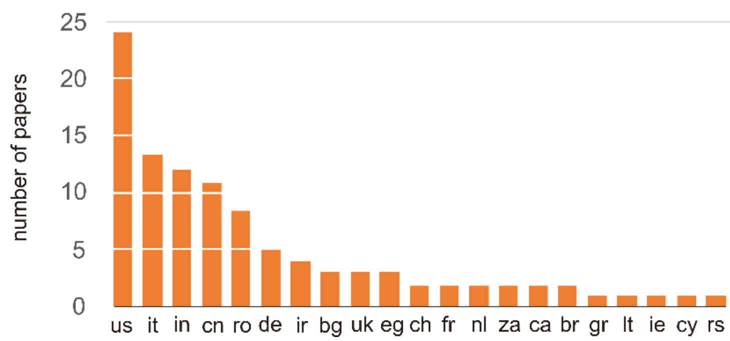

Figure 4 Number of IEEE papers with "power system" in the Publication Title, 2019

These results are not incontrovertible proof of anything in particular: the broadest of the search terms (must be IEEE papers, published in 2019) did not reduce the numbers sufficiently that serious study of their content could be undertaken as part of this work. Narrowing the terms did reduce the numbers to a more manageable level – these graphs show only a few hundred of the thousands of results. Nevertheless, as far as these results can be taken as representative, they are suggestive.

We infer that workers who regard their audience as "measurement people" publish in journals and conferences and magazines that have the word "measurement" in their title. Fully half the papers in this category that included "power systems" as author keywords (which we take as indicating that the authors regard power as a major thrust of their work) are working in Italy. This is a surprise in that while the IEEE is certainly an international institution (420,000 members in 160 countries), almost half the members are from the US, and we can reasonably infer that the other 50% is not all from Italy!

When the search terms are swapped, so that we look at work published in journals and conferences that can be expected to involve primarily power engineers, we see that the US is the largest contributor of papers that have "measurement" as an author keyword. The US fraction is less than 25%: the Italian contribution is about half that, but is still significant.

Two conclusions can be drawn from these numbers. First, it is evident that there are two separate communities (power, and measurement) and their profession activities do not overlap greatly. If we were to generalize, it seems that few members of the IEEE Power and Energy Society are also members of the IEEE Instrumentation and Measurement Society, and vice-versa. (It has to be admitted, however, that the search terms used in this study were not all-inclusive. They excluded four papers whose first author is one of the present authors [Kirkham] and published by IMS in 2019. The phrase “power systems” was not in the author keywords.)

The separation of the communities means that the benefits of interaction with others working in related fields is not being maximized. The bad news is that there are rather few people with a “foot in both camps.” The good news is that this small subgroup does tend to know one-another.

The other conclusion is that the US seems to be falling behind in terms of educating its engineers in the art and science of measurement. That remark should be interpreted as a complaint, but it is not aimed only at the US. A 2018 paper (Kirkham, Albu, et al., Teaching Measurement Fundamentals 2018) with authors from eight countries urged that “all engineering and science students be taught the basics of measurement theory and an overview of measurement infrastructure.” The authors went so far as to lay out the content of a possible course at university level, on the grounds that there is presently no pedagogy in the field.

One of the effects of this inadequate training in measurement is a widespread and misplaced confidence in the results of measurement. Measurement technology has advanced through a long revolution, a path from direct-reading instruments to digital measurement algorithms. This process has engendered this faith and confidence, and these days the numerical displays speak of high accuracy. The process, and the problem, are considered under the heading “The Digital Revolution” next.

3.0 The Digital Revolution

This small section of the Roadmap Report is included to provide a framework for understanding the exciting future that measurements in the power system now face.

The revolution began with the proliferation of direct-reading instruments, due in large part to the efforts of William Ayrton and John Perry, partners both in academia and in industry. But some scientists feared that simply reading a meter was going to lead to a future in which the user was no more than a “glorified plumber . . . an eminently useful drudge” (Boys, 1895)

It seems that such a pessimistic view of the capabilities of trained engineers was accurate. The power engineer of 25 years after those words were written was struggling to understand why it was impossible to measure power factor in a three-phase system. A special committee was formed to address the matter (National Electric Light Association 1919). The power engineer of today faces exactly the same problem and understands it no better. Reactive power has been a challenging measurement over almost the same period. (Lyon, 1933). It still is, more than 100 years after it was first named.

The advent of digital technology in the late 20th century added considerably to the capability of measurement systems. The measurement of reactive power can now be done using at least ten different algorithms. (Nelson, 2011). The results of these measurements do not, in general, agree with one-another. The differences are caused by distortion in the waveforms: the algorithms all assume undistorted sine waves.

And yet the modern power engineer has absolute trust in the results of his or her measurements. The modern engineer is not taught that the amount of trust that can be placed in a measurement result is something that should be known before the result is *used*. In the time of analog instrumentation, with a read-out that relied on a coil of wire rotating in a magnetic field, results might vary because of dust in the air gap, or electric charge on the glass, or temperature variations in the wiring. Those problems are largely gone with digital measurement systems. But the modern engineer is unaware that now the amount of trust depends not so much on the instrument making the measurement as it does on distortion of the signals being measured.

These are significant gaps in our teaching. They were predicted by Boys and others 125 years ago. An Appendix to the Report gives a brief history of how these gaps came about unnoticed. The short answer is that at every stage, as instrumentation technology got better, the science of measurement seemed more remote.

3.1 References

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4.0 Timing Accuracy & Synchronization

Timing is a cornerstone of reliable and accurate power system operations and control. Synchronization in time enables improved grid situational awareness and advanced data-driven grid control applications. Timing based on a Global Navigation Satellite System (GNSS) such as GPS is widely utilized in Intelligent Electronic Devices, Phasor Measurement Units and Digital Fault Recorders. It is crucial to evaluate whether this sort of solution meets the needs of measurements for IBRs.

(Behrendt and Fodero, 2006) reviewed the evolution of timing solutions from early-stage clocks to modern Atomic Clock and GPS Time. Five popular GPS clocks were studied, and their timing accuracy was evaluated through the statistical distribution of GPS timing and specific time protocols. Representative results for GPS clocks ranged from 50ns to 1ms, for 1 standard deviation (1 σ).

Time-stamping problems may be created if the time-stamp precision requirement exceeds the GNSS time accuracy.

NERC Standard PRC-002-2 (NERC 2015) requires that major system events should be time tagged within ±2 ms of UTC. Most applications for power system monitoring and recording are satisfied with timing accuracy to within 1ms, while synchrophasor measurements could provide timing accuracy to within 1 μs.

Lastly, the recently issued IEEE Standard 1588 (IEEE Standard 1588 2020) “Standard for a Precision Clock Synchronization Protocol for Networked Measurement and Control Systems”, could enable timing accuracy better than 1 μs for devices connected via a network.

4.1 References

Behrendt, K., and K. Fodero. (2006). The perfect time: An examination of time synchronization techniques. Technical Report, Pullman, WA, USA: Schweitzer Eng. Lab. Inc.

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5.0 The PMU

American Recovery and Reinvestment Act (ARRA) invested $4.5 billion in the electric sector — matched by private funding to reach a total of about $9.5 billion. Of the $4.5 billion, $3.4 billion was used to help industry accelerate the deployment of advanced technologies.

Smart Grid Investment Grant (SGIG) program over 6 year period and 99 competitively selected projects invested $7.9 billion. More than half of the investment was in advanced metering infrastructure (over 16 million smart meters), approximately quarter of investment was in electric distribution system (82,000 intelligent, automated devices) and some investment in transmission system (1,380 network PMUs).

During ARRA participants installed 1,380 PMUs and 226 phasor data concentrators. There are lessons learned in costs affecting device deployment, where device cost makes smaller contribution than labor, and operation of the equipment (ensuring security and communications).

During distribution automation effort[1] 82,000 intelligent/automated devices (automated feeder switches, capacitors, regulators, monitors, remote fault indicators, transformer monitors and smart relays) were deployed over 36 projects, that reported 39% as pilot-scale projects, 22% small-scale, 20% medium scale, and 19% deployed technology in full-scale deployments.

Technologies were applied in various use cases and scenarios, e.g. PMUs in frequency and voltage oscillation monitoring, intelligent/automated devices in automated controls for voltage and reactive power management, AMI in DER integration and grid planning and many more. One of the conclusions are that further deployment of smart grid technologies, tools and techniques can achieve favorable grid impacts; however, it involves changes in communications systems, workforce training, and business practices[2].

5.1 Standards

The performance of the PMU has been controlled by a series of IEEE standards. In 1995, Std 1344 was issued (IEEE Power System Relaying Committee, 1995). The working group that produced the document revolved around the four people who had been instrumental in developing the first commercial PMU: Arun Phadke and Mark Adamiak of AEP, Jim Thorp from Cornell, and Jay Murphy, whose company made the PMU. Phadke was the Working Group Chair, and Ken Martin of BPA was the Vice-Chair. Also on the working group were Stan Horowitz, Head of the Relay Section at AEP, and Gabriel Benmouyal (now with SEL), and Jack Kusters, a measurement engineer who had moved from the Canadian National Research Council in Ottawa to Hewlett-Packard to work on GPS calibrations for frequency standards.

Allowances were made in the standard for re-synchronizing to GPS should lock be lost, and the PMU was required to receive messages as well as send them. But the only “accuracy” requirements imposed were on the timing signal.

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[1] https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf

[2] https://www.energy.gov/sites/prod/files/2017/01/f34/Final%20SGIG%20Report%20-%202016-12-20_clean.pdf

In 2005 the standard was revised, and issued as (C37.118-2005, 2006). Thorp and Kusters were no longer on the Working Group, and while Phadke was, Martin was the Chair. Some performance requirements were levied, but seemingly not based on any particular application. Some of the “unusual” requirements were dropped from the previous standard, such as the use of a slow rate of return to GPS synchronization if lock was lost. “Accuracy” was now specified by something called Total Vector Error. The change to TVE likely reflects the absence of a “measurement” person on the Group: TVE prevents the propagation of errors, which is a customary requirement for a measurement system.

The following is an extract from the standard:

> NOTE 5—This standard does not impose any limitations to the use of PMUs under any conditions. PMUs are actually very good for making measurements under many transient conditions, and there have been many publications documenting this. The standard does not address the accuracy and response time under transient conditions, and so all testing is restricted to steady-state conditions. The problem with including transient performance requirements comes in stating requirements that are measurable, can be uniformly applied, and are not unduly restrictive on implementations. This is still an emerging technology and applying anticipated performance requirements could hamper development. Harmonizing a common set of dynamic performance requirements should be undertaken once the range of implementations and measurement applications has been more fully explored. At this time, dynamic performance under transient conditions should be specified and verified by the users to meet their application needs.

It is possible to sense a struggle in these words, a struggle between a desire to use the PMU in other than steady state conditions and a “feeling” that it should not be done.[1] Further, there is a sense that specifying “too much” would hinder the development of future PMUs. This sense was to carry over into the next version of the standard.

In 2011, the next revision of the standard issued as (IEEE C37.118.1, 2011). At the time it issued, Ken Martin was in the Chair, and Arun Phadke and Mark Adamiak were still involved, but not very active. Jay Murphy was a major contributor, and Harold Kirkham, an author of this Report, was a new member, having joined in 2009, when a good deal of the drafting had already been done. Although there was a later Amendment to “relax” requirements on the measurement of ROCOF (IEEE C37.118.1a, 2014), and a change to some details when the Standard was adopted by IEC as (IEC, 2018), this is for all practical purposes the current version.

This revision of the standard made an effort to specify performance requirements and to account for some real-world conditions. It was as good a standard as could be written at the time.

In hindsight, it can be seen that it fell short in some important regards. The following remarks are not made as an *ad-hominem* attack on the members of the Working Group: after all, one of us (Kirkham) was an active participant. However, the faults remain, and a future revision to correct them is needed. Changes are particularly needed for the application of the PMU to distribution, a topic discussed below. A major defect of the standard arises because the Working

[1] There is no hint of an awareness of the requirements of the GUM to explicitly include time as a variable in the measurement model if quantities were changing in time. Indeed, there is no sense of an awareness of the existence of a measurement model.

Group had the idea that the performance of the device can *only* be judged by test, and *must* be judged by test. In the real world of the power system, that is not the best approach.

For example, the standard specifies periods when the PMU allowable “error” is not specified because it cannot be known. The standard says:

> Note that the allowed TVE, FE, and RFE [here the “E” stands for Error] may be exceeded during a “transition time” before and after a sudden change in ROCOF is made. The error calculation shall exclude measurements during the first two sample periods before and after a change in the test ROCOF. (Italics added)

The exclusion creates a problem: the buyer of a PMU cannot know what it will do when the ROCOF value changes. Yet in the real world, ROCOF will change, more or less all the time. The exclusion is a spurious feature associated with testing. It arises through an incomplete appreciation of the underlying issue. The exclusion is not needed at all.

It is a fact that when ROCOF is suddenly changed during a test, the “frequency” or ROCOF cannot be specified across the interval. From the point of view of pure mathematics, that is true. What is not taken into account is that the act of measurement is not pure mathematics. It is the process by which the best “fit” of the measurement model is made to the actual signal. (Potter, 2000) Finding the best fit is not an insoluble problem at all. The PNNL PMU, in fact, operates on the principle of obtaining the best fit in the least-squares sense. The Standard, in this regard based on (Stenbakken & Zhou, 2007), assumes that the only possible reference for a measurement is mathematical, and the particular mathematics, involving a discontinuity in ROCOF, cannot be solved, and therefore a standard of reference is not available. Right idea, wrong conclusion.

There are more issues. Consider the following:

- The standard does not define frequency. It is true that there is a definition of “frequency” in the standard, but it is the textbook definition, and does not allow the frequency to change. In fact, the definition of frequency when frequency is changing is not a simple matter, and a paper exploring the problem was written in 2018 by Kirkham and two other members of the Working Group, Arun Phadke and Bill Dickerson. (Kirkham, Dickerson, & Phadke, 2018).
- Because the frequency is defined only in the textbook manner, the ROCOF is (by that definition) zero for all time. Since the PMU is obliged to measure ROCOF, the standard specifies how that must be done. The fact that the method of measuring is defined by the standard makes the standard an operational standard. In fact, this was not recognized at the time of writing the standard, because none of the members (Kirkham included) knew about this class of measurement. The Working Group maintained the attitude, inherited from the earlier WG, that to specify methods would be to inhibit technology development.

As a matter of fact (not opinion) the existing standards for the PMU are also otherwise operational. That is, in itself, not a problem. The fact that they are *not recognized* as operational is problematical. Once a documentary standard such as this starts to specify some of the operations that must be performed, a decision must be made whether the operations specified are operational *constraints* on a representational measurement, or whether the standard must become completely operational. Actually, the PMU standard applies many operational requirements, for example on the speed of response: two classes are created. Unless the fact of its operational nature is recognized, the standard will fall short of its potential.

It took many years, but the standard for measuring Partial Discharge is now regarded as operational. The technology is very complicated, and it happens that the operational requirements of IEC 60270 have not limited technology development or the competitive nature of the business. It has, however, ensured interoperability. The same is surely appropriate for the PMU.

5.2 "Conventional" Measurements

The most significant advance in instrumentation has doubtless been the phasor measurement unit, which has its origins toward the end of the 20th century, and gained prominence following the major blackout in the US North-East in 2003. It is a fairly recent arrival on the scene of measurement, made possible by the widespread distribution of a very accurate timing signal in the form of GPS. It is possible that the capabilities of instrumentation systems like the PMU have yet to be fully realized. Before we examine enhanced capabilities, we first look at what might be thought of as conventional applications.

A search in IEEExplore for papers on PMUs yields over 6000 hits. PMUs can be calibrated, simulated, made in a number of ways, shown to comply with a standard, optimally located in power systems, and written about in a dozen a dozen other quite interesting but far-from-groundbreaking ways.

Narrowing the search to those papers that are likely somewhat focused on measurement by including the word *uncertainty* in the search terms reduces that number to about 450 hits. (The search was not time limited, and *synchrophasor* was considered an alternative for *PMU*.)

A paper whose title included "Field data accuracy analysis" was thought to be of possible value in this study until it was realized that the authors evidently thought that simulation was a reliable source of truth. (Munir and Trisetyarso, 2016)

A paper on the effect of synchronization on uncertainty was interesting, but the work does not really point the way to a future use (Mingotti, Peretto and Tinarelli, 2018)

A recent paper examined the effect on estimating transmission line parameters by using synchronized measurements such as the PMU was also found not to point to an effect on the future of measurement. (Asprou, Kyriakides and Albu 2019)

A paper on "Uncertainty Quantification" was a consideration of the factors that could affect the application, based on the uncertainty of the results of the PMU. It was not particularly interested in the measurement aspects of the situation. (Chen, *et al.* 2105)

A member of the working group that wrote the PMU standard C37.118.1 wrote on using a digital simulator along with PMU data. Interesting and useful though it was, it was not greatly concerned with the subject of this report. (Ouellette, et al. 2011)

The paper that seemed to come closest to our topic was published 8 years ago (D'Antona and Mehdi 2012). The paper treats the effect of uncertainty in the PMU results on system calculations. The importance of the problem is stated thus:

> The network parameters and measurements data actually are affected by inaccuracies and have various uncertainties. Regardless of network topology errors, the performance of state

> estimator will be based on the accuracy of its inputs and the overall uncertainty of state estimator will depend on:
>
> - Uncertainty of Network Parameters.
> - Uncertainty of Measurements.
>
> Huge increase in the accuracy of just measurements might not significantly improve the overall State Estimator's uncertainty and it is essential to consider the uncertainty of network parameters in order to analyze the uncertainty of estimates properly.

The uncertainty is clearly an important quantity to know, and its effect resonates through power system calculations. This much is known, and the authors of this paper are well aware of the fact.

However, the idea of uncertainty is held to be defined conventionally:

> Please note that in this context we deal with "Uncertainties" not the "Errors". Uncertainty of a measured value is an interval around that value such that any repetition of the measurement will produce a new result that lies within this interval, while Error refers to the disagreement between a measurement and the true or accepted value.

The notion of rejecting "error" in favor of "uncertainty" is perfectly fair and valid, as error is based on the concept of a "true" value, as the authors of the paper point out. The fact that the result of a measurement has no "true value" to compare with was pointed out in (Kirkham, Riepnieks and Albu, *et al*. 2018). However, on its own this rejection of "error" does not solve the problem, because the definition of uncertainty is dependent on repeated measurement. The power system does not allow a "repetition of the measurement" so an uncertainty statement based on that idea is entirely meaningless, and its value cannot be found conventionally.

Nevertheless, the paper concludes by offering the opinion that including PMUs in the measurement suite improves matters. Their conclusion follows:

> In this paper, an approach is proposed in order to investigate the effects of PMU on WLS State Estimation considering different amounts of network parameters uncertainty. The approach is tested on IEEE 14-Bus power network test case and the results illustrate that by including two PMUs, the mean and standard deviation of voltage angle errors will be approximately 50 percent decreased. In other words, with inclusion of PMUs in the measurements, the accuracy of state estimator's voltage angles is doubled. Therefore, by using PMUs it is possible to decrease the sensitivity of WLS state estimator to the network parameters uncertainty because in practice, the parameters uncertainty has the major contribution to the standard deviation of the WLS state estimator error. It would be interesting to investigate the unbiasedness and sensitivity of the results to the choice of different measurement locations and in the future work a decision tree based approach will be implemented using a training set which composed of different measurements locations and different uncertainties along with different parameters uncertainty.

In previous work, we have argued that while the conventional measure of uncertainty is mainly a way to estimate the effect of definitional uncertainty, it cannot be evaluated in the electric power system. The results of measurements are never accompanied by uncertainty statements, but we have argued that a quality metric is needed (Riepnieks & Kirkham 2020). The notion of using a PMU to solve the problem will be further considered later in this report.

5.3 Expanded Capability Measurements

The PMU tackles a problem that includes dynamics. It is worthwhile to spend a moment looking at the difference that makes to the process of measurement. In a steady-state condition, measurements can be repeated (with the expectation of obtaining the same result). If the measurand is changing, then that change must be explicitly accounted for in the measurement model. This instruction is to be found in the GUM (Joint Committee for Guides in Metrology, WG 1, 2008). If only the frequency is changing, and the rate of change of frequency (ROCOF) is included in the measurement model, then the conditions are, in some fashion, again in a steady state. So long as the rate of change of frequency is indeed constant, repeated measurements will show that to be the case. However, the frequency value reported will show change from measurement to measurement. Nevertheless, the result of the measurement will be a good one so long as only the frequency is changing, and so long as ROCOF is included in the measurement model. PNNL has used the Goodness of Fit parameter to show that for a synthetic signal that meets this condition, the measurement quality is extraordinarily good.

However, as soon as the signal being observed is better modeled by having some parameter other than frequency change, the quality of the measurement deteriorates. Thus, if the amplitude of a voltage changes during the observation interval, and that change is not modeled, the quality of the measurement will be lower. Further, if the ROCOF is not constant, the assumption in the measurement model that it is constant will result in a lower quality measurement.

These aspect of the limitations of the PMU have not stopped people from making measurements of signals that are not well-matched by the PMU measurement model. To a natural extent, reporting of measurements that have dubious quality is inevitable. The PMU is programmed to report the results of its measurements at regular, pre-determined, intervals. If it happens that the signal is distorted, or represents the effects of a power system swing, the PMU will not know it, and will report even if the values are meaningless. But of more concern is the deliberate effort to use a PMU to report parameters it was not originally designed to measure.

Some authors are well aware of the limitations, of course. A paper that expresses the matter nicely is (Xie, Liu, Wang, Xu, & He, 2016):

> The existing dynamic monitoring devices and systems based on fundamental phasor, i.e. PMU (phasor measurement unit) and WAMS (wide area measurement system), cannot meet the monitoring requirements of sub- and supersynchronous oscillation. It is mainly because the existing PMU only measures the fundamental phasor without especially considering the sub- and supersynchronous oscillations. Moreover, other fractional and integral harmonics are filtered out to improve the measurement precision, which leads to the inaccurate reflection of the dynamic processes of sub- and supersynchronous oscillations.

These authors are correct that the PMU is made to deal with the fundamental frequency, and they are correct about the use of filtering. The details of some of the filtering is left up to the manufacturer, but the controlling documentary standard (IEEE C37.118.1-2011 and its derivatives) presents what is called variously a “system model” or a “reference model” of the PMU that includes various specifications for filtering, including the diagram shown here as Figure 5. Many manufacturers take the reference model as expressing requirements on the design.

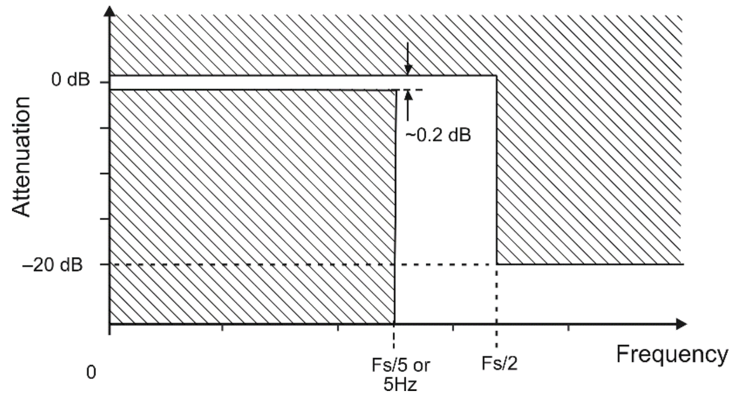

Figure 5 One of the Filter specifications in IEEE C37.118.1

The Fs referred to in the figure is the reporting rate. For a reporting rate of 30 reports per second, the maximum frequency that would get through the filter is about 15 Hz. Such a frequency might be relevant to the matter of subsynchronous resonance, but that should not be taken for granted in view of the various other filters included in the PMU. Furthermore, the reference model shows the result of the frequency measurement in the form of a weighted average based on four phase-measurement results:

$$\Delta F(i) = \frac{6\big(\theta(i) - \theta(i-1)\big) + 3\big(\theta(i-1) - \theta(i-2)\big) + \big(\theta(i-2) - \theta(i-3)\big)}{20\pi \times \Delta t}$$

The effect of this averaging is that the reported value will always be comprised of 10% of a frequency value based on an angle measurement made given three reports earlier, and 30% of the following report, and only 60% of the report including the most recent angle result. Smoothing is thereby achieved, and a sort of nonlinear low-pass filter.

All this filtering leads to the conclusion that the PMU is not the device for studying subsyncronous resonance in the usual meaning of the term—torsional resonance of the shaft of a generator. (At least, not the PMU that uses this algorithm.) However, there are other effects in power systems that give rise to changes in the system model parameters in a range that can be measured by a PMU. Low-frequency oscillations whose frequency is about one Hz or less are seen in large power systems such as those of the US and China, and PMUs have been used to study them.

Such oscillations typically involve an oscillation in the flow of power and can be seen in the frequency reported by PMUs at different parts of the system. In fact, although the word “phasor” has gradually changed it meaning so that it no longer is a complete representation of the signal being observed because “phasor” no longer includes the frequency, the local frequency is one of the prime indicators of changes in the behavior of large systems.

The graph of Figure 6 is adapted from the paper that first presented results showing frequency changing when a generator was suddenly taken offline (Faulk & Murphy, 1994).

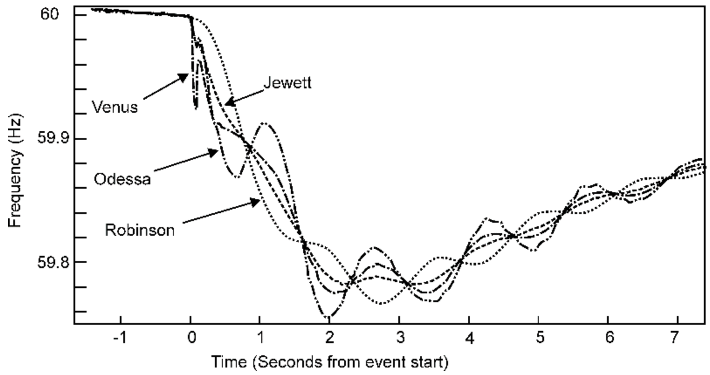

Figure 6 Multiple PMU reports of frequency, after Faulk and Murphy, 1994

The words on the graph are the names of substations where the PMUs were located. The drop in frequency was caused by a load rejection test (1150 MW were dropped) at Comanche Peak Unit 2. The paper begins by noting that

> The question of what happens to frequency across the Texas Utilities System when a large generator unit is tripped offline has been asked for several years . . . This past year, TU Electric teamed up with Macrodyne, Inc. to try and capture the frequency across Texas when the Comanche Peak Unit No. 2 full load (100%) 1150 MW load rejection test was performed on July 27, 1993 . . . The original question on frequency can now be answered with a definite “Yes”, it does vary and is a function of the location from the disturbance and the amount of generation that exist at the moment of the loss of generation.

The rapid oscillations had never been observed before, and many people at the presentation of the paper thought there must be a measurement error!

It is now accepted that such electromechanical disturbances do not propagate instantaneously, though the typical presentation conceals some of the detail. The graph of Figure 3 shows recordings of PMU results for a generator loss in the WECC. The Apparent simultaneity of the frequency drop is an artifact of the graph: the entire graph of Figure 6 would fit into two-thirds of the width of one of the vertical scale marks of Figure 7.

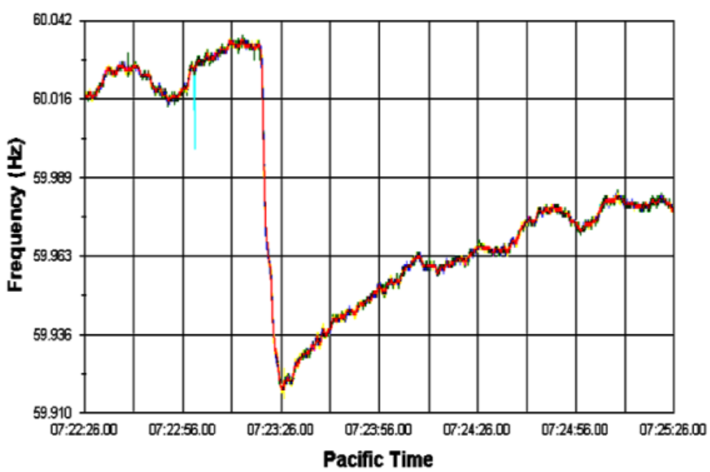

Figure 7 Generator drop in the WECC

The frequency response needed by a PMU to be able to capture such an event can be estimated using Carson's formula. (Carson, 1922) Working on the technology of frequency modulation (which was not used for broadcast radio until more than a decade later), Carson proposed that the bandwidth could be approximated[1] by

$$\text{Bandwidth} = 2(\Delta f + f_m)$$

In words, the required bandwidth is given by twice the sum of two terms, one representing the amount by which the frequency would be modulated, the other the highest modulating frequency. What Carson produced was a formula that was useful in the linear world we use to conceptualize such things.

Applied to the data in Figure 7, we can see that the first term (the change in frequency) is about 0.2 Hz, and the second term is about 0.7 Hz (some of the oscillations seem to have a period of about 1.4 s). The bandwidth requirement is thus 2(0.2+0.7) Hz, a little less than 2 Hz. Such a bandwidth is less stringent than the limits set in C37.118.1, and provided that the PMU is reporting fast enough, at least a few times a second, the results should be meaningful.

Carson later introduced the term "instantaneous frequency." (Carson & Fry, 1937) For the purposes of studying FM, instantaneous frequency was modeled by a constant frequency added to a part that was variable. While the notion seems straightforward, in fact the topic is a subject of much disagreement. One of the problems is that the mathematics requires that the signals represented by Carson's formula (which is also at least hinted at in the C37.118.1 standard) must be unbounded in either time or frequency (Jones & Boashash, 1990). Three review papers (Boashash, 1992a) (Boashash, 1992b) (Cohen, 1989) contain over 200 separate citations on the topic. (Cohen, 1989) observes that while a large amount of energy has been devoted to clarifying the topic, and very many plausible attempts have been made to describe a chirp as a time/frequency distribution, "the behavior of each distribution is dramatically different."

The topic can certainly be regarded as incomplete. The lack of cohesion is not a problem of power engineers alone, in fact the power community is very much peripheral to the matter. However, those in the power community who discuss the matter as if the concept was clear are almost certainly not aware that they are, metaphorically speaking, skating on thin ice.

5.4 The Distribution PMU

Consideration is being given to the use of the PMU in the distribution system. There are many profound differences between the transmission system and the distribution system, and these are largely unrecognized in the PMU community. It is worthwhile to highlight a few.

- The distribution system handles most of the power in the generation and transmission systems, and yet is so much more diffuse that the financial considerations are vastly different. Since electric billing is done by kilowatt-hours (mostly) the flow of power down a line has a more or less constant relationship to the flow of money in the other direction. The numbers are thousands of times smaller in distribution.

[1] The approximation is such that the formula actually yields a number that contains about 98% of the energy of the FM signal. At an FM transmitter, 2% of the energy would be further from the carrier center frequency than this formula would indicate, and that may give rise to unwanted adjacent-channel interference. However, for the purposes of designing a filter, that is useful. For giving an idea of the effect on a dynamic frequency measurement, it is also useful.

- Because the dollar-flow is not large, the resources have not been available to instrument the system outside the substation. There are exceptions, or course, and DOE has invested resources in what used to be known as Distribution Automation, but the truth is that most distribution systems operate unmonitored.
- Until recently, the unmonitored nature of distribution meant that a power outage was not known to the utility until someone phoned it in. That situation is still true in many areas. Participants in the webinar responded to the question “What types of outages are most vulnerable for being mis-qualified because of missing/unreliable measurements?” Their responses, while not restricted to distribution, were largely in the area, and included:
    - common mode and dependent type of outages
    - lightning-related outages
    - tree-related outages
    - fuse failures
    - recloser failures
    - pole-top (distribution) transformer issues,
    - intermittent line issues (especially during high-wind or storm conditions)
    - frequency excursions being mistaken as outages
    - voltage dips being mistaken as outages

Tree and other vegetation contact outages present not only an immediate challenge in determining the equipment and crews to dispatch, but can produce very different signatures by climate zone and forest type when the tree remains in contact with the line. Accurately classifying vegetation contact outages can lead to some unexpected ways to improve reliability: Dominion found that certain line segments in particular were heavily prone to vegetation contact outages no matter how well they maintained the trim zones (Hodies, 2017; Power Info Today, 2017). It turned out that the bulk of the outages on those segments were happening during high wind conditions with material from outside the trim zone—when the vegetation is flying through the air, a bigger trim zone may not help. Those segments were then targeted for strategic undergrounding, though proving the case to regulators for investment needed substantial study support (Sweeney, 2017).

Other issues during high-wind and storm conditions can present signatures/causes that can be hard to identify correctly, as the webinar participants noted. High heat can cause line sag, and high wind under high heat can cause the stretched conductors to contact, for example. [He et al 2019] discussed the under-representation of lighting outages in the Federal Aviation Administration's (FAA)official outage classification data.

Recloser failures can present some interesting behavior outside of expected fault signatures. [Cordova et al 2019] presents an example where the data from a recloser controller did not fit any expected fault event signatures. Further study determined that a significant circulating current event initiated when the recloser closed.

- The topology of the distribution system is largely radial, whereas the transmission system is always interconnected. Interconnection brings the advantage of a large improvement in connectivity between a source and a load. That advantage is missing in the distribution system. It is estimated that, as a result, around 80% of the outages at a home are caused by faults in the distribution system.

- The quality of the signals in the distribution system is abysmally low, taking the sinusoidal model as a quality reference. It was stated in (Ochoa, 2014) that the average Total Harmonic Distortion on the current of a feeder was between 2% and 98%, and that "Most feeders (65%) were found to have between 10% and 20% average THD." For comparison purposes, the THD in transmission is typically 2 or 3%. The same report notes that "Average THD increases significantly (above 20%) in feeders with PV, particularly for PV penetration levels above 30% of customers. This suggests future growth in PV connections could increase harmonics levels in the future." This is clearly not the world of the transmission system, and a different kind of treatment of the signals is needed.

  In a transmission system, the power flow on a line is calculable from the line inductance value and the voltage at the two ends if the phase angle between these voltages is known. If we write the voltages as V and the line impedance (end to end) as X, the power flow is a function of the angle δ across the line, as in

$$P = \frac{V_1 V_2}{X_{1-2}} \sin \delta_{1-2}$$

  The angle dependence is why the PMU made such a difference in the level of the awareness of system condition. Even if the two "ends" are not the end of a single line, but are two distant points in an interconnected system, the phase angle gives an indication of the power flowing. Further, if the angle is oscillating, a system swing is indicated.

  It is natural to imagine that the same calculations would be relevant in the distribution system, but they are not. The relation between the phase angle along a distribution circuit and its power flow is very different. Power flow in a distribution circuit gives rise to a voltage drop along the line, and scarcely an angle change. The line is best modeled as a distributed resistor, not a lumped inductor. According to (von Meier, Stewart, McEachern, Andersen, & Mermanesh, 2017), the angle can be estimated from

$$\delta_{1-2} \approx \frac{XP - RQ}{|V_1||V_2|}$$

  Whereas the angle across a transmission path may be a few tens of degrees, the angle across a distribution circuit is very much smaller. The same reference includes the following:

  > This paper uses the term "μPMU" generically for devices (from any manufacturer) specifically designed to measure distribution-level phase angle separations—i.e., small fractions of a degree—and "PMU" to include devices that meet expectations for the transmission context, with typical accuracies on the order of 1º.

  The indication that the phase angle is "a small fraction of a degree" is fair. To observe that such an angle cannot be measured by an ordinary PMU in the presence of the noise and distortion on the system is also fair. The μPMU accomplishes this feat, but the paper does not make clear how. It might be filtering the signal, though that would greatly reduce the response speed, and that does not seem evident. Perhaps the system estimates the parameters and solves the network equations.

In transmission, a *direct* measurement of two angles provides information about the power flow through the area between the two locations where the angles were measured, even without detailed knowledge of the system in-between. There seems to be no corresponding capability in a radial distribution system. Nor is there a need: the power down a line can be directly measured at the sending-end, as it could in transmission.

The angle difference in the transmission system is a matter of the “big picture” and giving an operator a rapid system awareness. Angle was also a value available after a load-flow study was complete—it was obtained as an output of the modeling. It was not until the PMU was developed that the value could be an input to the calculation. It is not obvious what exactly is gained in distribution if the angle is estimated as an indirect measurement, using knowledge of the power and reactive power, along with the system resistance and inductance parameters.

None of the foregoing should be taken as suggesting that the PMU should not find a place in distribution. The fact that the PMU gives an angle will sometimes be a useful feature: when two feeders are to be paralleled: it is important to know their relative phase, though an uncertainty of a few degrees is not usually a matter of concern. It is also important to know the angle and the frequency if an island is to be resynchronized after a break-up. The advent of DER generation in the distribution system makes the PMU results useful. However, provided the frequencies are well-enough matched, the knowledge of the angle to within a few degrees is likely to be acceptable.

There is another aspect to the situation, too. The distribution system has historically been neglected from the measurement point of view, and any new measurements would be useful. The future of measurement in general surely includes the synchronized reporting of results, and that is accomplished by the PMU.

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6.0 Point-on-Wave (POW) Measurements

Widespread deployment of PMUs has led to increased recognition of the value of high resolution, time-synchronized measurements. Valuable as PMU data is, its widespread use has also resulted in a recognition of limitations. In particular, PMU results model the input waveforms as sinusoids, and give the magnitude, frequency and phase. To represent the waveform directly, higher-resolution measurements are required. Such Point-on-Wave (POW) measurements are currently available in a limited capacity through instruments such as power quality meters and digital fault recorders (DFRs). The authors of (Silverstein and Follum 2020) note that there is increased interest in waveform measurements with greater availability and time-synchronization. The term Continuous Point-on-Wave (CPOW) is introduced in (Silverstein and Follum 2020) to communicate this concept.

(Silverstein and Follum 2020) discuss the drivers, potential use cases, and barriers of CPOW measurements in detail. Listed drivers include:

- the widespread deployment of inverter-based resources (IBR),
- increasing use of series capacitors and HVDC lines,
- interest in asset health monitoring driven by successes with synchrophasor data,
- changing load characteristics.

These drivers are closely related to the document’s proposed use cases, which include IBR monitoring and integration, subsynchronous resonance detection, power quality evaluation, and asset health monitoring.

The commonalities among these drivers and use cases are the associated high-speed grid behaviors that cannot be well represented by PMU or SCADA data. The high reporting rates required to make these behaviors observable in waveform measurements are also barriers to CPOW.

While acknowledging the communication, processing, and storage challenges that CPOW poses for today’s electric power industry, the authors of (Silverstein and Follum 2020) conclude that widespread adoption can be achieved. Their suggestions include

- distributing data analytics,
- employing cutting edge archiving technology developed for the power industry,
- utilizing cloud-based applications,
- learning from other industries that routinely deal with high volume data.

In addition, they note that making waveform measurements more available than they currently are from power quality and DFR systems does not necessarily mean that data must be streamed continuously. For some applications, data could be stored locally and polled as desired. This approach offers some benefits, but advances in digital communication technology may make it unwarranted.

It is now possible to transmit digital data, in large quantities, very reliably. Because of that it may be possible to migrate the process of measurement from the field to the control room, or to company HQ. One may envision a module handling the input voltage and current, and a separate module performing measurements, with isolation between them. The measurement could be of power, or for the PMU parameters. The generalized point-on-wave (POW) data is essentially a version of the data going across this interface from the input to the DSP. There is, in principle at least, no reason for the two parts of the instrument to be housed in the same box, nor is the measurement limited to power or the PMU calculation. In two separate instances, streaming CPOW measurements have already been deployed to monitor for subsynchronous resonance (Zweigle 2015, Wall 2016).

Multiple measurements can be made, operating on copies of the same signal, and their parameters can be changed at will, once the DSP part of the process is no longer many kilometers away in the reaches of the power system. We will see later how the PMU can play a much more important role than the one shown here.

IEC 60044-8 defines what are called Merging Units to accomplish the tasks shown in the center of Figure 8. The assumption behind the use of a merging unit is that the current transformers and voltage transformers have digital outputs. It may be that the document would accomplish all that is necessary in terms of what may be called (in system engineering language) an Interface Control Document for Point-on-Wave measurements.

Many grid automation projects involve the Process Bus (IEC 61850-9-2) and digital or analog merging units. This equipment utilizes sampled values over ISO/IEC 8802-3 and is usually part of the Local Area Network for communications and involves capture of voltage and current signals, consolidation, processing and further transmission of data. To better facilitate implementation and enable interoperability the IEC 61850-9-2LE was created. A usual sampling rate for merged sample value stream is 80 samples per cycle. Communication is usually realized through Ethernet.

It seems at the moment that, in terms of being an ICD, the specifications in IEC 61850 are in a state of flux. But chances seem good that a suitable solution can be found. At least the general principle is accepted in some parts of the power industry. The topic is discussed in more detail under the heading Communications.

The uses for the output of the merging unit functionally illustrated in is limited only by the imagination. Since the actual source-signals, essentially digital versions of what is available at the sensor itself, are available for inspection, it will be possible to detect unusual conditions in the voltages and currents, and to take account of their effect on the various measurement systems.

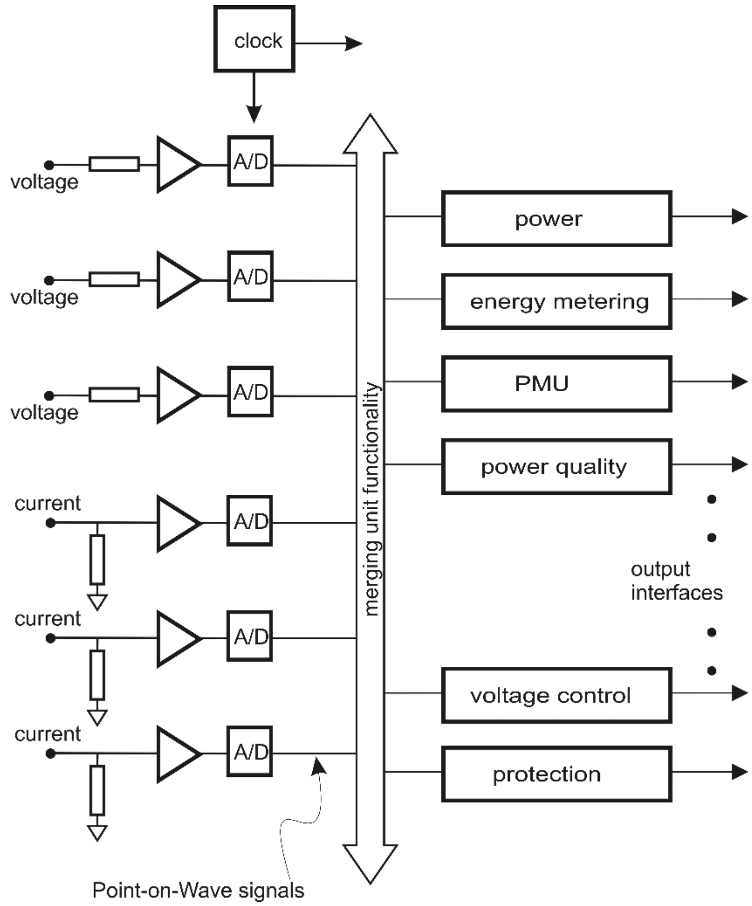

Figure 8 Conceptualizing Point-On -Wave measurements

6.1 References

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7.0 Communications and Storage for POW Data

Communication networks for data exchange can be divided into Local Area Networks, Neighborhood Area Networks and Wide Area Networks. The same categorization can be kept when looking at data storage questions.

7.1 Local Area Network (LAN)

A Local Area Network (LAN) is best described as information exchange within a limited geographical area, like a transformer station or generation facility. Setting up a LAN for sampled value data exchange within a transformer substation for IEC 61850 is a routine activity (Yang, Dolezilek and Cenzon 2020). Standards and technology exist capable of the exchange of POW data via what is known as Process bus communication (Skendzic, Ender and Zweigle 2007).

A standard of particular interest is IEC 61850-9-2 (IEC First Edition, 2005). Substation LAN implementation usually is over an Ethernet based network. Some key equipment is being made that is crucial for real-time POW based applications, in particular devices known as merging units. For high-speed applications packets are time-stamped with an accuracy of a few microseconds or better. Under specification IEC 61850-9-2 the sampling rate is between 80 samples (for protection) and 256 samples (measurements) per period (Grasset, no date). This can load the network at 5% and 12.3% accordingly for a 100 Mbps Ethernet link. Even though the bit rate on the channel is not large, the timing and latency requirements (3-6 milliseconds for protection application (Maragal 2016)) emphasizes proper settings and optimal network architecture for switching devices on two networks:

- Ethernet based Process Bus
- Time Synchronization network.

For extensive multi-device networks with limited telecommunication capability there are also some data compression approaches documented, that would allow to compress the data to less than half of the original size. This also has benefit of shorter encoding/decoding times (Blair, Roscoe and Irvine 2016).

Within the LAN, messages are not externally routable, meaning that network routers cannot forward messages through different networks. The messages reside in the single local network, in this case the Process Bus.

Local storage for locally hosted applications is already a familiar feature of the power system, for example for Digital Fault Recorders. These instruments are used to record POW data during an event. Large scale distributed storage for all generated data most likely would not be considered economically worthwhile or feasible and would introduce more security risks.

7.2 Neighborhood Area Network (NAN)

A Neighborhood Area Network (NAN) is used to connect multiple LANs or devices in more geographically distant areas. The geographical impact necessitates technology for message routing. Here also multiple examples exist.

An emerging technology for communications for protection is routable GOOSE. It can be used for distance protection, transfer/direct trip, interlocking multi-phase reclosing, current differential protection and phase compensation protection (Maragal 2016). Several communication technologies are available (mainly Ethernet, Ethernet over optical fiber and LTE (aka 4G)) that can meet the latency requirements of protection while utilizing GOOSE. The channel data rate of 100-Mbit indicates that overall bandwidth demands for multiple devices in a multi-substation NAN would not be a problem.

Routable GOOSE is also used for remedial action schemes with worst case bandwidth requirement of 0.4 Mbps and latency requirements of <10ms. (These numbers can be compared to those required for PMU communications under IEEE C37.118. 2: they are 4 Mbps bandwidth and 100 milliseconds to a few seconds latency (Maragal 2016) .) While probably on separate virtual networks, the underlying technologies for this protocol and application could reasonably be used for POW.

A NAN can also implement the same LAN data compression methods and also provide more centralized data storage capabilities. Data can be stored and monitored with advanced analytical capabilities.

The storage requirements for currently used PMU data could be from 10 TB (Maragal 2016) (300kB per second) to hundreds (NASPI Engineering Analysis Task Team (EATT) 2019) of TB per year. POW data stream that would be similar to DFR recorded data would amount up to 500TB per year for a NAN of 10 data streams.

7.3 Wide Area Network (WAN)

Once the messages are routable, they can be routed through networks and transferred any distance. There are optimization issues (like protocol overhead) and performance constraints (routing and switching times) that come with that. These are usually addressed with specific Wide Area Network (WAN) communication protocols (e.g. Internet Protocol) and long-haul technologies (optical fiber networks).

An existing example of large volume low latency data collection is PMU data collection (Taft, NASPInet 2.0 Architecture Guidance 2019). It is based on the IEEE C37.118.2 protocol.

Another example is Gateway Exchange Protocol, which is an open source transport protocol meant to exchange time-series data. It was revised and is currently undergoing standardization process as IEEE P2664 (Streaming Telemetry Transport Protocol). When the standard is approved it can be adopted for wide area POW data transmission. From polling results obtained during the PNNL Webinar, its main anticipated use is PMU measurement streaming, but some also see uses for POW streaming as well.

New web-based open source protocols, like Web Real-Time Communications (WebRTC) used over Internet for teleconferencing and real-time video streaming could also be used for some applications, transferring POW data over the internet. See, for example (WebRTC n.d.). However, the Internet-based technologies and standards are probably further away from Utility use than STTP.

It is worth noting that disruptions by 5G (Taft, 2019) and Starlink (Starlink 2020) technologies are probably in the distant future for utilities.

7.4 Webinar findings

During the webinar sessions, the audience was introduced to the notion of evolving requirement changes in telecommunications (comms) and current technologies that the participants might be seeing out in the field. An example of a new generation of communications protocol was shown. It was the DOE and Grid Protection Alliance project on Streaming Telemetry Transport Protocol (STTP).

The audience was then asked to provide feedback (full results are shown in Appendix 9.4). When asked where they see the most considerable potential for STTP, participants indicated streaming PMU data (12 votes) rather than POW (6 votes). Notably, seven respondents indicated that they haven't heard about the STTP until now.

Next, participants were asked to indicate their experience with various smart grid-related technologies (STTP, PMU measurements, substation process bus, routed GOOSE) and assess on a scale from "unplanned" to "implemented." The results show a wide range of situations; however, the PMU measurements come out as the most implemented from the list. That indicates the success of programs like NASPI and Grid Modernization Consortium. Information on STTP implementation indicates an early pilot-project phase, most likely for PMU measurement transfer, substituting for current C37.118.2. Other technologies, like process bus and routed GOOSE are in a similar situation, being either in the pilot, early adoption phase, or even not planned.

Finally, the audience was asked to evaluate the most relevant gaps that hamper reliable broadband telecommunication roll-out to the edge of the grid. Overwhelmingly the primary obstacle that was mentioned was cost (both initial and operational). Another significant obstacle was indicated in comms technology. After discussing the results, a clarification was noted that here, technology was meant as missing the necessary comms infrastructure rather than non-existent technology. Gaps in policy or in utility "mentality"/corporate willpower were not emphasized as much.

During discussions, the usual questions on data, analysis and potential comms requirements were discussed. From the POW measurement perspective, there is a clear trade-off between performing analysis at the spot of measurement, performing centralized analysis, or having a hybrid approach. No clear agreements on these topics indicate that possibly an experimental, iterative, and tailored process could be a way forward.

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8.0 Analysis and its Instruments

Waveform-type analysis has long been a topic of interest in power system operations and control in both industry and academia. In this section gaps have been identified from the domain application perspective. In addition, a short market survey was performed covering several commercial products for power measurement.

8.1 Power Quality Analysis

IEEE Standard 1159-2019 (IEEE PES Transmission and Distribution Committee 2019) defines power quality as, “The concept of powering and grounding electronic equipment in a manner that is suitable to the operation of that equipment and compatible with the premise wiring system and other connected equipment.” That really is not a useful definition, however, and recognizing that, the working group moved it from the Definitions section of the 1995 release of the standard to an Annex in the 2009 release. (The IEEE Dictionary has the same definition.)

Quality is a difficult word to define. A reasonable definition for the present purpose might be grade or character of goodness, or fitness for purpose. Applied to power, it may be taken as an indication of how close the power system signals are to being well represented as sinusoids.

The assessment of power quality therefore has to do with assessing the distortions on the waveforms and their constancy. Recall that a sinusoid has constant parameter values, so a voltage that is well-represented by a sinusoid has constant amplitude. Low power quality can include voltage dips or voltage that is outside statutory limits. What is acceptable power quality for a refrigerator may not be acceptable for an incandescent light, and a PC may have yet different needs. There is no single, simple, set of requirements for the measurement.

Interest has historically been considered primarily within a facility, or at its interface with a distribution system. As modern power systems and their measurements evolve, there may be increased benefit from applying knowledge from the power quality community to the bulk power system.

Table 4, which is reproduced from (IEEE PES Transmission and Distribution Committee 2019), lists power quality phenomena and their characteristics. Many of the categories shown have spectral content or durations that can be captured only with waveform measurements. As detailed in (IEEE PES Transmission and Distribution Committee 2019), waveform measurements of current and voltage are either analyzed directly or used to calculate a wide range of power quality metrics. The field of power quality will furnish much data if waveform measurement instruments become widely deployed to support grid modernization. Recent work is going beyond what might be called conventional power quality analysis. This work will be considered below.

Table 4 Categories and Characteristics of Power Quality Phenomena. Reproduced from (IEEE PES Transmission and Distribution Committee 2019).

Categories	Typical spectral content	Typical duration	Typical voltage magnitude
1. Transients			
1.1. Impulsive			
1.1.1. Nanosecond	5 ns rise	< 50 ns	
1.1.2. Microsecond	1 μs rise	50 ns – 1 ms	
1.1.3. Millisecond	0.1 ms rise	> 1 ms	
1.2. Oscillatory			
1.2.1. Low frequency	< 5 kHz	0.3 – 50 ms	0 – 4 pu
1.2.2. Medium frequency	5 – 500 kHz	20 μs	0 – 8 pu
1.2.3. High frequency	0.5 – 5 MHz	5 μs	0 – 4 pu
2. Short-duration root-mean-square (rms) variations			
2.1. Instantaneous			
2.1.1. Sag		0.5 – 30 cycles	0.1 – 0.9 pu
2.1.2. Swell		0.5 – 30 cycles	1.1 – 1.8 pu
2.2. Momentary			
2.2.1. Interruption		0.5 cycles – 3 s	< 0.1 pu
2.2.2. Sag		30 cycles – 3 s	0.1 – 0.9 pu
2.2.3. Swell		30 cycles – 3 s	1.1 – 1.4 pu
2.2.4. Voltage Imbalance		30 cycles – 3 s	2 - 15%
2.3. Temporary			
2.3.1. Interruption		> 3 s – 1 min	< 0.1 pu
2.3.2. Sag		> 3 s – 1 min	0.1 – 0.9 pu
2.3.3. Swell		> 3 s – 1 min	1.1 – 1.2 pu
2.3.4. Voltage Imbalance		> 3 s – 1 min	2 - 15%
3. Long-duration rms variations			
3.1. Interruption, sustained		> 1 min	0.0 pu
3.2. Undervoltages		> 1 min	0.8 – 0.9 pu
3.3. Overvoltages		> 1 min	1.1 – 1.2 pu
3.4. Current overload		> 1 min	
4. Imbalance			
4.1. Voltage		Steady state	0.5 – 5%
4.2. Current		Steady state	1.0 - 3.0%
5. Waveform distortion			
5.1. DC offset		Steady state	0 – 0.1%
5.2. Harmonics	0 – 9 kHz	Steady state	0 – 20%
5.3. Interharmonics	0 – 9 kHz	Steady state	0 – 2%
5.4. Notching		Steady state	
5.5. Noise	Broadband	Steady state	0 – 1%
6. Voltage fluctuations	< 25 Hz	Intermittent	0.1 – 7% 0.2 – 2 Pst
7. Power frequency variations		< 10 s	± 0.10 Hz

8.2 Distribution System Power Quality

A study done by the University of Manchester and the local distribution company, Energy North West, identified the lack of instrumentation in the typical distribution system (Ochoa 2014). The study installed monitoring systems on 200 low voltage networks, developing techniques to add instrumentation without requiring customer interruptions. Details of the operation of each phase on over 1000 feeders were monitored during 2012 and 2013. Some of the substations (which would typically be rated at about 1 MVA) were selected because of nearby PV installations. 15% of them experienced reverse power flow. Nine substations had voltages above 253 Volts (the nominal value is 240) and four had a little as 216 volts at the busbars some of the time. Unbalance exceeded 2% at seven.

This information is not information that is normally available, as distribution systems are hardly monitored. More was found. The total harmonic distortion (THD) on the current “varied between 2% and 98%, although most feeders (65%) were found to have between 10% and 20% average current THD.” It is interesting to note that none of these findings were particularly associated with an identified problem, from the point of view of either the utility or the customer.

Power factor was also monitored. The results encouraged the utility to change the “default power factor assumption” from 0.95 to 0.98 in the algorithm for estimating load “across the *whole* secondary network.” (Italics in the original.)

Part of the report includes recommendations for performance evaluation of the network. This is presently rarely done. It was recommended to monitor line-neutral voltages and phase currents at the head of all feeders. That has to do with understanding congestion. The end-points of the feeders should also be monitored. Voltage should be monitored every 10 or 15 minutes, and currents (or power and reactive power) every hour.

It was recognized that the amount of monitoring being recommended was much more than was usual in a distribution system. It was also acknowledged that the future use of smart meters would likely play a major role in this monitoring.

Whether the smart meter actually does effect the recommended level of monitoring is a matter of some interest, and a factor to be watched.

The study, which reported in 2014, led to a further study, concentrating on the voltage rather than the current. There has recently been interest, perhaps particularly in Europe, in revising the view of what is considered acceptable voltage in terms of power quality. Most places have their own standards to define what is acceptable quality in the broadest sense.

In the US, the voltage on a LV outlet is often described as “120 V,” but it is “allowed” to be up to 6% away from that. One explanation of the value is that Edison chose to deliver power at 110 volts, possibly because interrupting DC at greater voltages was challenging. When the systems were changed to AC, it was found that the voltage at the customer was not so much lower than at the source than it had been with DC, and many customers were receiving over 110 volts. As time went by, some utilities gradually inched the voltage higher, so as to increase their revenue, but the practice was ended in the 1940s when a standard value was set. The current standard is ANSI C84.1-2011 (ANSI 2011). It gives several ranges of voltage.

In Europe, most countries historically had their own standards, but these are now set by European Norm 50160 (TC8X_WG1 2005), which was defined to allow the use of existing equipment in the UK (which had been at a nominal 240-V level) and some European countries that had been using 220 volts. The standard is now 230 volts. Realistically, not much changed when EN 50160 came into force in 1999.

To examine whether the voltage ranges could be relaxed, a very large study was undertaken in England. The goal was to test two hypotheses:

- Customers will not notice a decline in service standards if the permissible ranges for voltage and harmonic distortion are widened;
- If customers do notice, their perception of power quality and overall satisfaction are not adversely affected.

Voltage measurements from over 7000 LV networks were analyzed. The results, presented in a Closedown Report (Kennelly, Pearmain and Brainch 2015), may be considered surprising. There was no evidence that voltages outside the standard range caused a decrease in customer "satisfaction." (The report did observe that the same cannot be said of supply interruptions.) Customer satisfaction was obtained via a telephone survey of customers that were identified has having experienced a voltage outside normal limits. Winter responses were separated from summer, and were found to be more critical. About 4000 measurements were made of harmonic distortion at 12 distribution substations. THD was found to be rarely above the 5% "planning tolerance" level.

All in all, the correlation between voltage and customer satisfaction was found to be "very weak."

It is possible that the use of modern power supply systems in appliances has resulted in a decreased impact of power quality issues. It was concluded that the hypotheses being tested were indeed true, though mention of THD was removed from the findings, and the "satisfaction" wording softened:

- Customers will not notice a decline in service standards if the permissible ranges for voltage are widened;
- If customers do notice, their perception of power quality and overall satisfaction are unlikely to be adversely affected.

The study was performed for a utility (Electricity NorthWest) because they wanted to permit the system to operate beyond normal limits to allow more PV to be installed, and more EVs to be accommodated without incurring the cost associated with system reinforcement. In other words, this effort was part of the planning effort for a transition to a low-carbon economy.

Increased monitoring and increased levels of DER and EV are connections to be watched.

8.3 Light Flicker

It is also possible that the electronic power supplies power supplies that are relatively immune to power quality problems are also the cause of some of the same problems. For example, LED lighting will not usually have the same responses to voltage changes as the older incandescent lights did. The incandescent light caused regulation of voltage to be accomplished in steps smaller than about 0.6% so that the customer would not observe "flicker." That also created a need to measure flicker, and an industry to create flicker meters. DOE recently announced the report of a study of handheld meters (DOE, 2019).

The measurement of light flicker is a completely operational measurement. That means that the quantity “flicker” is not defined, but the method of measuring it is. For example, The IEC illustrated a flickermeter with the diagram in Figure 9 .

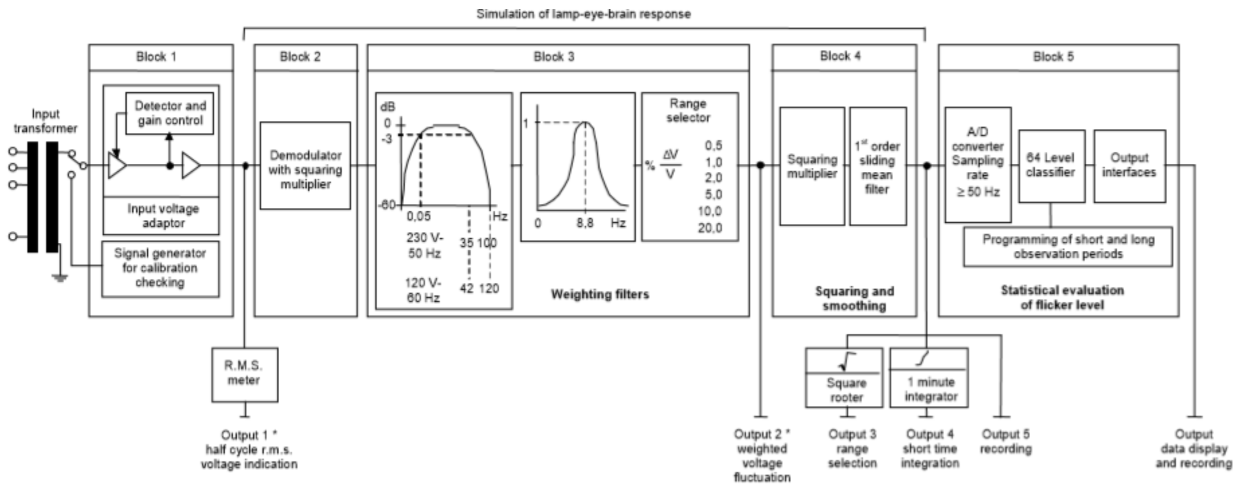
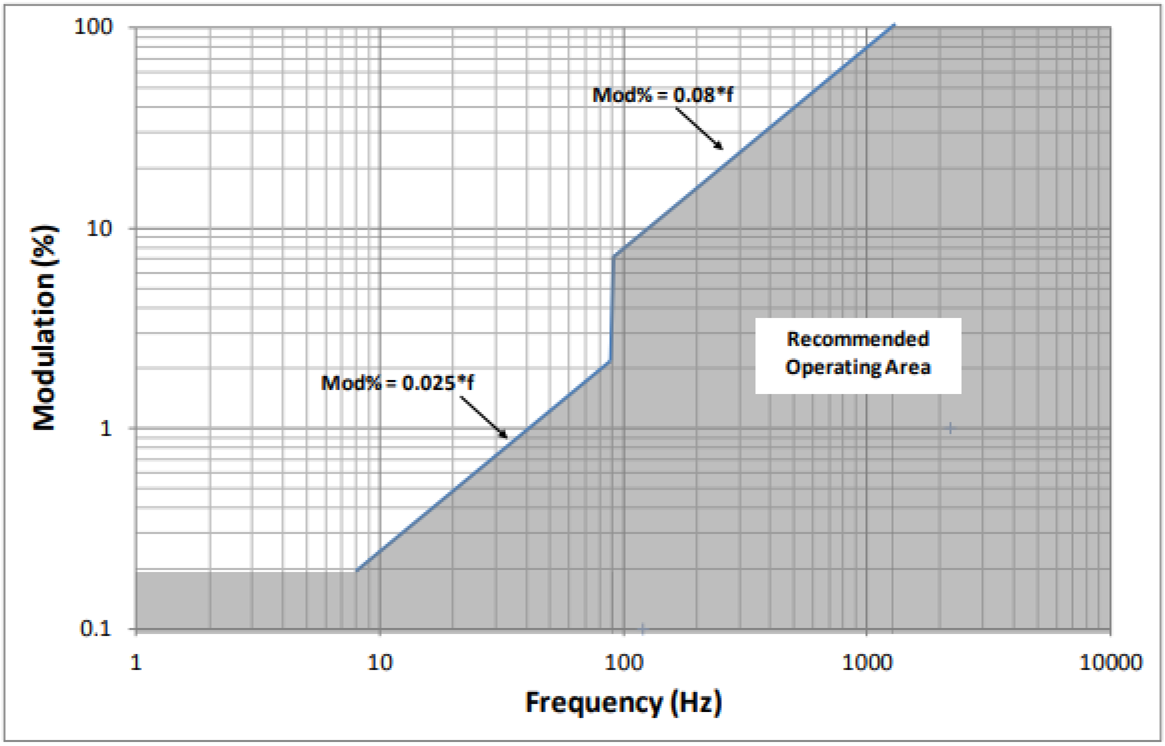


Figure 9 Flicker meter based on IEC 6100-4-15 2005

Several organizations are interested in the standardization process for the flickermeter. In addition to the IEC, ANSI, DIN, CENELEC, NEMA, and IEEE are involved. IEEE, for example, issued Std 1789-2015, IEEE Recommended Practices for Modulating Current in High-Brightness LEDs for Mitigating Health Risks to Viewers in June 2015. This standard explains that the processes in the IEC standard are based on modeling the incandescent light and the eye-brain interaction via a series of filters (block 3 in Figure 9). While Standard 1789 does not present a functional block diagram similar to the one shown in Figure 9, it does give a graph showing the relation between modulation depth and frequency and what it calls a Recommended Operating Area. Figure 10 is a copy of Fig 20 from the Standard.



NOTE—Operating in the shaded area minimizes visual discomfort or annoyance and also gives low risk for headaches and photosensitive epileptic seizures. Below 90 Hz, Modulation (%) is less than 0.025×frequency. At or above 90 Hz, Modulation (%) is below 0.08×frequency. Modulation (%) = 100 × ($Lmax – Lmin$)/($Lmax + Lmin$) where L_{max}, and L_{min} correspond to the maximum and minimum luminance, respectively. The figure was derived from the low-risk regions in Figure 18.

Figure 10 Copy of Fig 20 “Recommended Practices Summary” from IEEE Std 1789

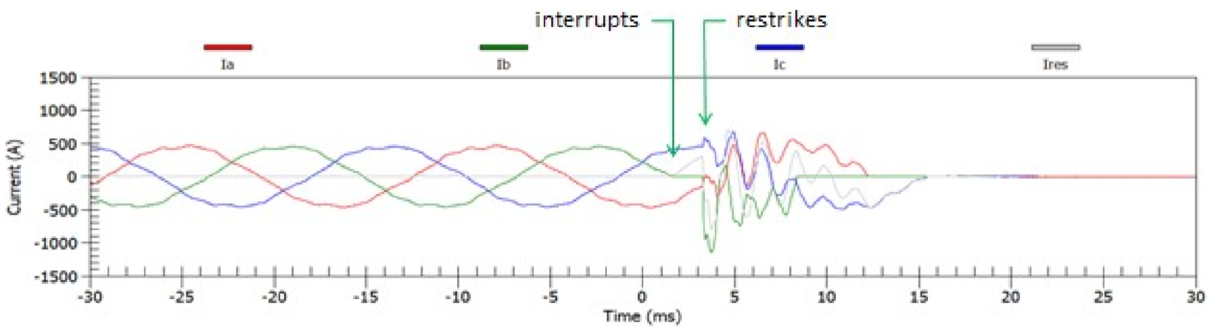
8.4 Power Quality “Signature” Application

A “signature” in the waveforms can sometimes be used to identify equipment failures. The IEEE PES Working Group on Power Quality Data Analytics recently released a report discussing the topic (IEEE PES Working Group on Power Quality Data Analytics 2019). The authors introduce the report by stating:

> In recent years, engineers and researchers in the field of power quality, power system protection, and equipment testing have realized that useful information can be extracted from the waveforms for the purpose of equipment condition monitoring. In the field of power quality, for example, power quality monitors routinely collect power disturbance data. Some of the data do not indicate the existence of a power quality problem but they have been used to detect the presence of abnormal equipment operation in the system.

Thus, the power quality community has already begun to address asset health monitoring, one of the use cases of CPOW measurements identified in (Silverstein and Follum 2020), using waveform measurements. The report provides a comprehensive review from a Power Quality (PQ) data analytics perspective. The analysis method consists of collecting waveform-type power disturbance data, extracting signature information, and from this information identifying various power equipment failures. One aspect considered using the data to identify shorted capacitor elements. The work showed that considerable work troubleshooting parts can be avoided.

Figure 11 shows the waveform signature data from a power quality meter (PQM), and its cause by arcing and pitting along the arcing horn of circuit switcher. Moreover, catastrophic transformer failure due to arcing can be prevented (Irwin 2010), with fewer power disruptions due to equipment failure. Figure 12 illustrates voltage and current waveform data which had initiated transformer maintenance. It was reckoned that a catastrophic failure was prevented.



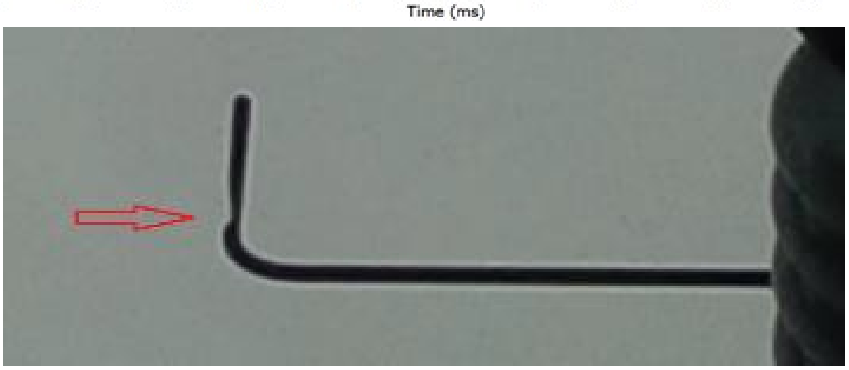


Figure 11 Waveform with restrike of a capacitor bank (upper) and Pitted arcing horn of a capacitor bank (lower) (After IEEE PES Working Group on Power Quality Data Analytics 2019).

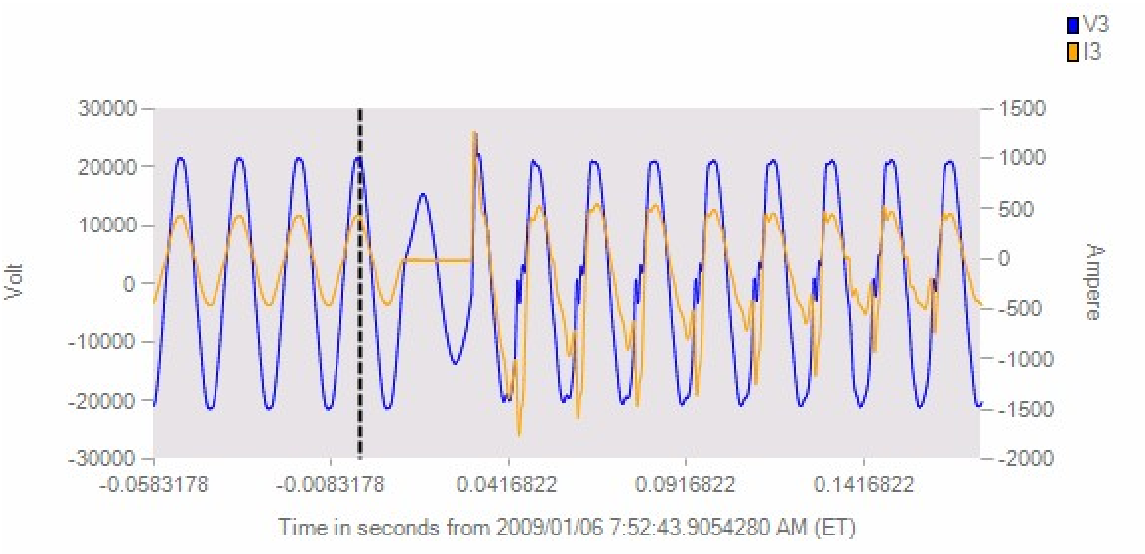


Figure 12 Zero current waveform data during transformer load tap changer failure (Irwin 2010)

One gap identified in (IEEE PES Working Group on Power Quality Data Analytics 2019) is the challenge of signature detection and information extraction. There is considerable diversity in the signatures of different types of power system equipment failures. As a result, new methods are needed to bridge the gap between the collected waveform data and limited actionable information from existing data analytics.

One gap that has been identified is the inconsistent implementation of equipment programming, data capture, and display from different manufacturers. This could cause significant challenges for any large utility with a multitude of equipment suppliers. On the other hand, calibration and self-testing are seen as related to ordinary electrical measurements. The drift rate, temperature coefficient, location to calibrate, calibration intervals, calibration injection points, self-testing, and practical field check procedure should be well documented. Failure to do those things has been identified as a gap. The large volume of equipment owned by a utility may cause problems given the limited availability of protection/verification engineers.

Standard 1159 of (IEEE PES Transmission and Distribution Committee 2019) provides a list of well-defined terminologies on power quality phenomena, which lays a common ground for the use of the appropriate instrumentation by power industry and academic researchers. It also gives detailed measurement techniques, application scenarios, and monitoring result interpretation.

General commercial PQMs sampling at 256 or 512 samples per cycle might be adequate to understand most system disturbances. But there are also other PQMs with much higher sampling rates, e.g. the Eaton Power Xpert 8000 Meter sample high-speed transients at 6 MHz, which is equal to 100,000 samples per power cycle (assuming the system frequency is 60Hz). It can support general metering/logging and intelligent isolation of sub-cycle transient (Eaton Corporation 2006). Anti-aliasing is also integrated by using a statistical data cleansing method. In summary, industry vendors can provide products with high sampling frequency; Eaton’s products demonstrate that there is no shortcoming in terms of sampling frequency from the manufacturer’s perspective.

8.5 Power System Protection

The power system protection community is probably the single most influential group in the profession. It was from this community that digital relaying emerged, and the PMU. The digital fault recorder is a common tool, and waveform analysis has been of interest in fault location for some time.

In terms of evolution, electromechanical relays were followed by solid-state relays, and then microprocessor-based relays. The US lagged in many regards. The ability to host complex protection algorithms made an impact eventually. These systems can be configured with multi-facet functions, additional benefits from their supporting communication infrastructures are also significant (IEEE PES Power System Relaying Committee 2009).

Potential gaps in current microprocessor-based relays are 1) short life cycle for both hardware upgrade and software design, 2) susceptibility to transients (especially early in their development), and 3) the complexity involved in operational setting and testing. Figure 13 shows typical waveform data for offline relay testing. It contains three stages of testing, they are pre-fault, during fault, and post-fault stages. This specific example is from one transmission line series compensation study.

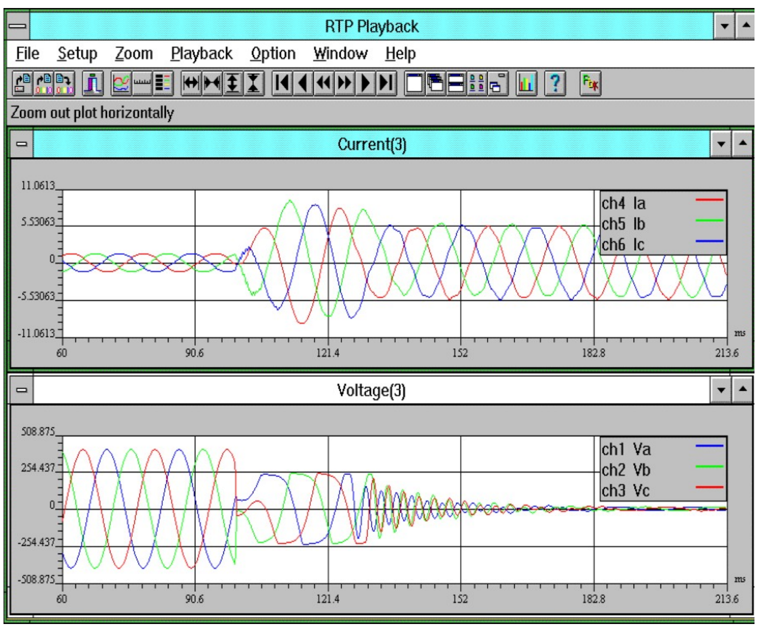


Figure 13 An example for playback screen during offline relay testing (After IEEE PES Power System Relaying Committee 2009).

Another gap is from the utility asset management perspective. No unified solution is available to manage such a fleet of protection relays; it is highly possible that they are from multiple vendors with various models and customized settings/variations. Finally, how to prioritize and balance different functions within the same equipment also poses challenges, especially during specific transient periods around system disturbances.

8.6 Power System Disturbance Analysis

Echoing some of the gaps that are identified in power quality analysis and protection equipment management, (Perez 2010) also confirms the challenges of being a good event analyst, which requires system protection knowledge, practice, and years of experience. It should be noted that system disturbance data captured by digital fault recorders (DFR) is usually with short durations (range from cycles to seconds). In comparison, continuous point-on-wave data with data resolutions similar to that from a DFR suggests the possibility of routine monitoring.

For most scenarios, DFRs offer “specialized, specific and dedicated microprocessor equipment with far superior sampling rates, record lengths, and unfiltered recording abilities” (Perez 2010). Figure 14 shows the waveform data for a two-second voltage transient record by a DFR. It is noted that the subfigure (b) indicates that DFR only captures a very short duration record, and as shown in subfigure (c), the corresponding RMS values of the oscillation were analyzed with a rate of 1 sample per cycle.

Due to its pre-defined triggering mechanism and “stand-by” mechanism, one gap in DFR measurements is that it might miss some disturbance, or any disturbances associated with only slightly mis-operating systems (Silverstein and Follum 2020). During the webinars hosted by the literature review team to engage with stakeholders, participants were asked if they knew of instances where needed measurements were unavailable because a DFR did not trigger. Of the 17 responses received, 4 indicated Never, 4 selected At least once, 8 responded Sometimes, and 1 chose Often. These results seem to support the claim that pre-defined triggering is a gap that could be addressed by CPOW instruments.

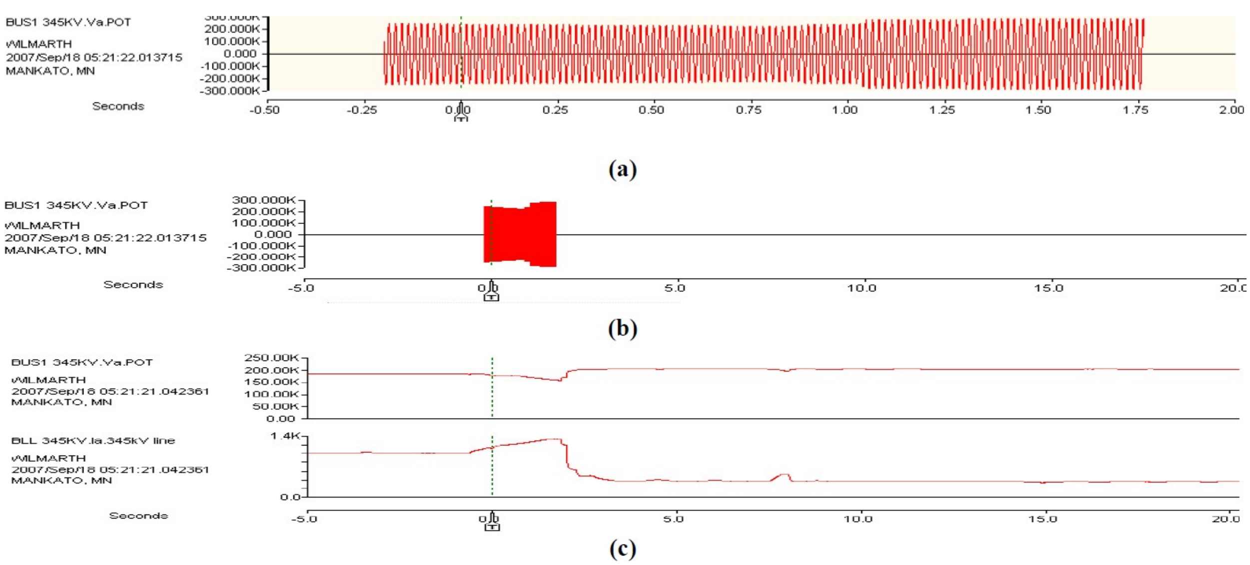


Figure 14 DFR waveform record for voltage and current in one transient and swing event (Perez 2010).

Even if an organization’s DFRs trigger on every event of interest, the data may not be available for use in a broad array of applications. When webinar attendees were asked how accessible DFR measurements are in their company, 10 responded that it was only available at the device for some engineers. A nearly equal number, nine, indicated that the measurements were available in specific systems for engineers. One participant responded that DFR data is freely accessible and shared within a company they work with. In a follow-up with this participant they described the implementation as, "…automated waveform analytics are an integral part of operations with email notifications customized by job function going out to over 400 employees (from line crew foremen to senior executives) within 2 minutes [of] a disturbance." These results indicate that while data availability may be a gap for many organizations, technical solutions do exist, at least for the relatively short record lengths produced by today's DFRs.

8.7 IBR-related SSR Phenomena

The sub-synchronous resonance (SSR) phenomenon was first discovered in 1970, when the Mohave Generating Station experienced a turbine shaft damage event. Compared to the nominal system frequency, the frequency range of SSR is lower. But it is higher than power system inter-area oscillation frequencies (0.1Hz~1Hz), as well as most of the power system local oscillation frequencies (1Hz~10Hz). The traditional solution to identify SSR is the Frequency Scan (FS) approach, which has been widely adopted by the power industry.

With the vast expansion of inverter-based resources (IBR), SSR events have been observed near some IBRs. For most of the observed events, SSR is related to the series compensation equipment near those IBRs; series compensation is employed to increase the transmission network transfer capability of long transmission corridors. In 2019, the IEEE PES Task Force on Modeling Subsynchronous Oscillations in Wind Energy Interconnected Systems published a white paper (IEEE PES Wind SSO Task Force 2019) in which some recent SSR events that happened in U.S. and China were analyzed and state-of-the-art detection/mitigation technologies were reviewed. Figure 15, which is from the white paper, shows that the current data from all three phases shows dominant frequency components in the range of 9 Hz to 13 Hz. Additional frequency components with lower magnitude are also visible in the range of 37 Hz to 43 Hz.

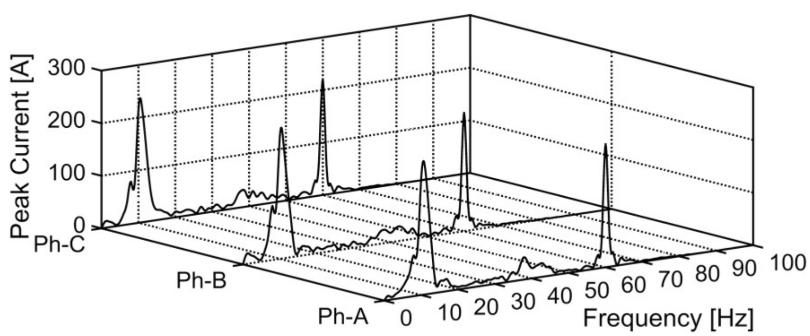


Figure 15 Frequency component based on DFT analysis of three-phase current waveform data from a wind plant (After IEEE PES Wind SSO Task Force 2019).

Cheng, Huang and Rose (2019) propose a new frequency scan methodology, which aims to resolve the SSR phenomenon when inverter-based generators are connected through series capacitors. The transmission elements' reactance for each sub synchronous frequency (5~55Hz) needs to be scanned; moreover, time-domain EMT PSCAD simulations are required to perform evaluation and verification. Figure 16 shows the conventional frequency scan analysis for SSR; reactance crossover indicates potential Subsynchronous Control Interaction (SSCI). But it is challenging to perform such on-demand analysis in a regular routine, and newly installed units nearby could impact the previous analysis.

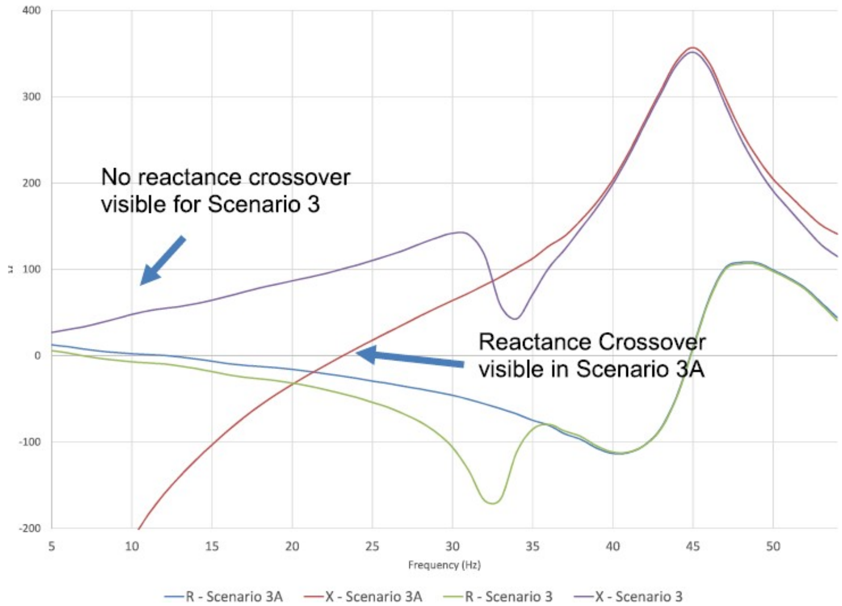


Figure 16 An illustration of frequency scan results for transmission line impedance under different frequencies. The plots for R and X in Scenario 3 do not cross, but there is reactance crossover for Scenario 3A. (From Cheng, Huang and Rose 2019)

Moreover, it should be noted that field measurements to further verify the proposed method are not generally available. This shows a gap; a well-established procedure for integrated measurement and simulation solutions is needed in utility practice. Considering the ever-changing operating conditions of IBRs, and the potential interactions among nearby transmission elements and other IBRs, high-resolution waveform data could be leveraged to enhance the grid operators' monitoring of renewable generation. This can also benefit the utility planning process, for both generation integration study and transmission enhancement study.

8.8 IBR-Related High Frequency Resonance (HFR) Phenomena

By definition, the super synchronous resonance phenomenon, or High Frequency Resonance (HFR), has a frequency range above the system fundamental frequency. It differs from subsynchronous resonance also in that the resonances happen under different conditions. SSR occurs under conditions on the series compensated transmission cable, in which inserted series capacitance is inserted intentionally; on the other hand, the HFR occurs under conditions of the shunt capacitance connected to the transmission cable (Song, Ebrahimzadeh and Blaabjerg 2018).

In the view of Song et al. high-resolution measurements not only provide a more detailed description of power grid behaviors at system frequency (i.e., 60 Hz in North America), but also enhanced visibility of power grid behaviors at high-order harmonic ranges, i.e., HFR above the frequency of 1 kHz. Figure 17shows the results from time domain simulation, which confirms that the impact of transformer leakage inductance. One gap identified in this research is that no field waveform measurement is available for such analysis; all the results are either from theoretical analysis or software-based time domain simulation.

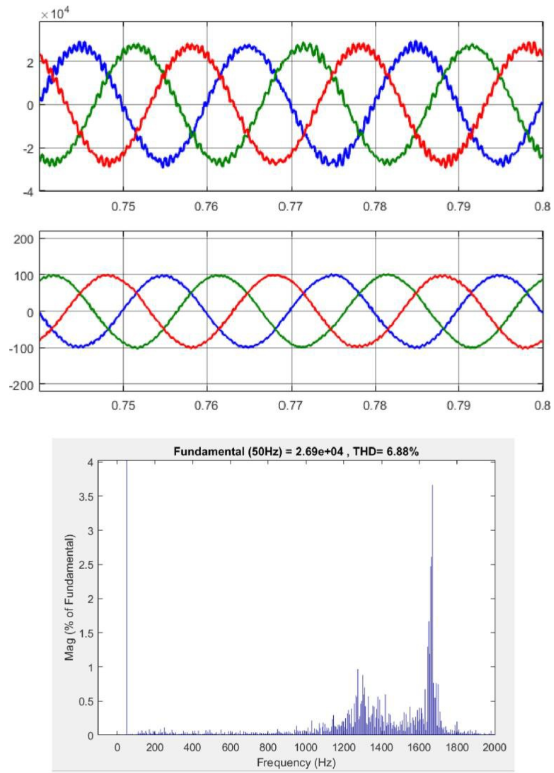


Figure 17 Simulated AC bus voltage and current with HFR phenomenon, and FFT analysis for AC bus voltage peaking at 1670 Hz (Song, Ebrahimzadeh and Blaabjerg 2018).

On the other hand, it is essential to differentiate the potential causes for HFR. It is demonstrated that variations in wind turbine rotor speed and output power is irrelevant to HFR, but the modeling of transmission line impedance and transformer leakage inductance shows that the magnitude peak may shift.

Lastly, the impacts from the inverter controller design should also be considered. In Rotor Side Converter (RSC) and Grid Side Converter (GSC), the current control bandwidth using a proportional integral (PI) controller is usually from 125 Hz to 250 Hz, which is normally 1/20~1/10 of the converter switching frequency. Depending on the location and sampling rate, high-resolution waveform measurement may provide a way to analyze the performance of such controllers.

It is also important to recognize that HFR is not limited to IBRs. Lin (2005) gives an example in which two harmonics in HVDC current measurements (717 Hz and 600 Hz) are the two main principal AC components; while another two harmonics, 67 Hz and 167 Hz, are the main sources to induce electromechanical resonance on the nearby conventional turbine generators. Figure 18 shows the HVDC current waveform measurements. To further extend this phenomenon to an IBR context, when IBRs are interfaced with HVDC; waveform measurements could be of great benefit to support such harmonic analysis and related SSR or HFR events.

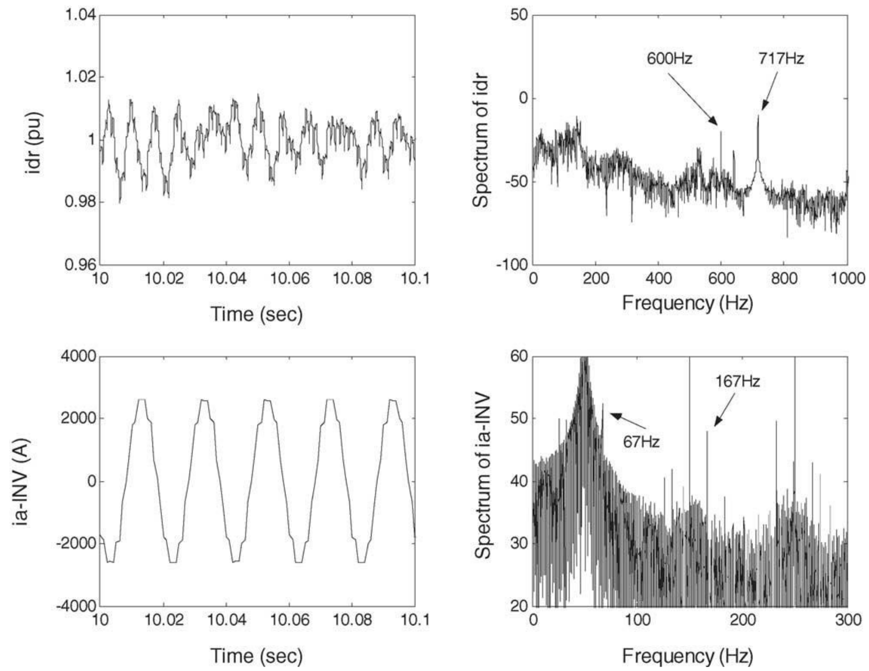


Figure 18 Detailed illustrations for current waveform measurements and their FFT analysis results (From Lin 2005)

8.9 Short Market Survey on Available Commercial Measurement Products

This literature survey has so far discussed existing measurements systems including SCADA, PMUs, DFRs, and PQMs. It has also highlighted the concept of CPOW, which the authors of (Silverstein and Follum 2020) suggest is a future technology that will be necessary as power grids continue to modernize. In this section, a brief survey of specialty measurement systems that sit between the conventional and the futuristic is provided. The technologies presented here were selected to highlight relatively new commercial offerings that demonstrate the industry's progress towards advanced measurement systems.

8.9.1 CANDURA iPSR

The CANDURA intelligent Power System Recorder (iPSR) is marketed as a recorder that can, "…stream high resolution waveform and RMS data to memory continuously with no gaps and no loss of fidelity" (CANDURA Instruments 2020). Waveform measurements can be recorded at up to 1024 samples per electrical cycle and synchronized using GPS or IRIG-B. SCADA systems can be used to retrieve some information, but waveform streaming is not available. Thus, the CANDURA iPSR is not a CPOW device. Still, the instrument demonstrates that many aspects of CPOW devices are presently available.

8.9.2 GridSense from Franklin Electric

Franklin Electric Grid solution provides intelligent electronic monitoring devices that serve a broad array of customers, including the power utility, telecommunications, data center and industrial critical power markets. Their main products include a circuit breaker monitor (OPTIMIZER2), a load tap changer (Model 1250- LTC), and distribution and sub-transmission line monitoring (GridSense Line IQ). In this report, we focus on GridSense Line IQ (Franklin Electric 2020), which monitors overhead network lines up to 138 kV. It is an innovative, self-powered instrument, which can continuously capture the following data:

1. Fault waveform
2. Load profile
3. Power factor
4. Line status and condition
5. Ambient and conductor temperature
6. Time-stamped event recordings
7. Fault direction

The detailed technical specifications are listed as follows:

a) Sampling rate: 600 Hz for Current and Voltage Measurement
b) Power source: Solar with battery backup
c) System memory: 100 events (60 sec RMS records); 32 fault waveform (200 ms), up to 85-day load profiling
d) Communications: Local RF 150 ft (50 m); Cell (GSM/CDMA), Landline; DNP3, Web Services SCADA & historian integration tools available

8.9.3 MM3 Intelligent Sensor from Sentient Energy

Sentient Energy provides multiple commercial products in the power system measurement equipment market. Its customers include Manitoba Hydro, Pacific Gas and Electric Company (PG&E), Florida Power and Light Company (FPL), and others.

The MM3 Intelligent Sensor (Sentient Energy 2020) is a Linux-based instrument. Its measurement capability includes current, conductor temperature, voltage characteristics. In addition, it is equipped with an onboard accelerometer, GPS, and secure Bluetooth.

Some of the technical specification are listed as follows:

a) Sampling rate: 130 samples per cycle, which is equivalent to 7,800 samples per second
b) Power source: Magnetic field, self-charging, no battery, but requires 6-A line current
c) System memory: gigabytes of local storage
d) Communications: Wireless, Secure Bluetooth for local communication, can process date locally and forward detailed data only upon operator request or when bandwidth is available

Sentient Energy also provide another product, UM3+ Line Monitor, which can detect, capture, analyze and communicate faults and non-fault disturbances, which occur on underground cables and equipment. It can sample at a rate of 256 samples per cycle, which is equivalent to 15,360 samples per second, it can communicate using either Advanced Metering Infrastructure (AMI) or Distribution Automation (DA) mesh networks and cellular providers.

8.9.4 Grid Monitoring Platform from Aclara

Aclara's grid monitoring platform can support utilities for real-time fault detection, continuous power quality monitoring and asset management (Aclara 2020). Aclara's power sensors are for distribution monitoring, which features battery-free sensing and high accuracy (less or equal to 0.5% accuracy). Aclara also provides inductively powered sensors for a wide variety of waveform data based distribution networks applications, such as power measurements, oscillography, and fault/transient alarming. GPS-enabled location and auto-phase identification are another two important features. Their customer includes NV Energy, DET Energy, Manitoba Hydro, and Western Power Distribution.

Some of the technical specification are listed as follows:

a) Sampling rate: not available in datasheet, but indicates that it can capture waveform data and save in COMTRADE format

b) Power source: Inductively powered

c) System memory: not available in datasheet

d) Communications: Wi-Fi, CDMA, 4G LTE, over-the-air upgradable

8.9.5 Other Commercially Available Sensors

Besides the listed three manufactures in grid measurement equipment market, there are many other vendors and manufactures; moreover, there are active research teams from academia, which are also actively looking into new sensing techniques and more future products.

In December 2018, the Office of Electricity developed a multi-year program plan (MYPP) for a new program, Sensor Technologies and Data Analytics (https://www.smartgrid.gov/sensor_technologies_and_data_analytics). Development of the MYPP builds on the technology review, assessment, and roadmapping that have been published by the DOE Grid Modernization Initiative (GMI) Sensing and Measurement Strategy project.

Four projects are listed on the website:

1. Transformer Real-time Assessment iNtelligent System with Embedded Network of Sensors and Optical Readout

   Palo Alto Research Center (PARC) and its research partners will develop, prototype, and demonstrate TRANSENSOR, an innovative, low-cost optically-based monitoring system that will increase the capacity of grid infrastructure to accommodate accelerating the integration of DER.

2. Sensing Electrical Networks Securely and Economically (SENSE)

   Georgia Tech Research Corp. and its partners will develop and demonstrate a low-cost sensor network for monitoring the health of distribution transformers. The sensors will be capable of measuring voltage, current and temperature. This technology will be able to be used with capacitor banks, reclosers and fuses.

3. Sensors with Intelligent Measurement Platform and Low-cost Equipment (SIMPLE™)

   COMED and its research partners will develop voltage/current sensors with enhanced accuracy, bandwidth and harmonic range and high measurement granularity for medium voltage distribution system monitoring, protection controls. This technology will be well suited for applications such as voltage sensing and regulation, frequency support, fault detection and location, distribution system state and estimation, and electrical distribution network topology processing.

4. Advanced Intelligent Sensor Development and Demonstration for Future Distribution Systems with High Penetration DERs

   The University of Texas at Austin and its research partners will leverage existing and emerging sensor measurements to enhance data-driven observability and develop robust estimation and identification techniques to enable real-time grid-wise monitoring and modeling of loads and distributed energy resources.

In a 2017 presentation (https://www.smartgrid.gov/files/Divan_Georgia_Tech_SENSE.pdf) given by Prof. Deepak Divan from Center for Distributed Energy, Georgia Tech, he reviewed multiple commercial products, which were available in the market at that time. They are given as follows:

5. Wireless Sensor for Overhead Lines (SEL)
6. Lighthouse MV Sensor (Tollgrade)
7. Powerline Sensing using Backscatter (EPRI, SwRI, TVA)
8. Stick on Sensor from UNC, TVA and EPRI
9. Transformer IQ (GridSense/Incon)
10. GS200/250 Line Sentry (Grid Sentry)
11. MM3 (Sentient Energy)
12. OptaNODE Distribution Transformer Monitor (Grid 20/20)
13. Coresense (ABB)

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9.0 Inverter-Based Resources (IBR) Model Validation

The growing penetration of inverter-based resources (IBR), e.g. distributed energy resources, renewable generation, and electronically connected loads, has resulted in new challenges for the reliable electrical grid operation, analysis and control. To successfully solve these issues, it is critical to have accurate models of IBR. Several big reports on the IBR modeling have been published by major industry organizations, including NERC (NERC 2020a), CIGRE (Yamashita et al. 2018), and IEEE (Standard P2800 under development[1]).

The dynamic stability simulation tools (e.g., GE PSLF, PTI PSS/E, PowerWorld, TSAT) traditionally used for Bulk Power System (BPS) studies are based on the positive sequence phasor dynamic models sometime also referred to as root mean square (RMS) models. These models were initially developed to simulate the dynamic behavior of synchronous generators and have been successfully used for several decades. The models iteratively solve a system of algebraic and differential equations in the phasor domain (50 or 60 Hz). With the growing penetration of IBR, the positive sequence phasor models of IBR were also developed and implemented in major power system simulation tools (Asmine et al. 2011, NERC 2010, Ellis et al. 2011). More accurate second generation generic renewable generation models were developed by the WECC Model Validation Working Group (Pourbeik 2013, WECC 2019).

Positive-sequence phasor models of IBRs have certain limitations because the fast dynamics of inverter controllers are represented using simplified models (e.g. phase lock loop and inner current control have to be simplified, and modeled as constants or simple algebraic equations, the converter phase-lock loop (PLL) is neglected) (Pourbeik et al. 2017). These limitations mean that positive sequence models of wind/solar generators do not work well for studies when an IBR is connected to a weak system (NERC 2017b, Fan 2019). In contrast with positive sequence models, Electromagnetic Transient (EMT) models take into account fast dynamics in IBR controllers. EMT software tools solve systems of differential equations in the time domain (Isaacs 2019). Major EMT simulation software tools include: ATP, EMTP- RV, PSCAD/EMTDC and DigSilent (EMT mode). EMT simulations are traditionally used for different studies that require very detailed modeling of various power system components, e.g. harmonic analysis, sub-synchronous resonance, HVDC control design, model validation, weak interconnections, and high IBR penetration cases. Recent advancements in parallel computing make it possible to apply very computationally-intensive EMT simulations to bigger and more complex systems (Isaacs 2017). Hybrid Simulation platforms (e.g. Electranix E-Tran) enable performing co-simulation using EMT and Transient Stability Analysis programs (PSCAD and PSS/E) (Irwin et al. 2012, Isaacs 2019).

Recent studies conducted by NERC found systemic modeling issues with BPS-connected PV resources in the interconnection-wide base cases (NERC 2020a). For instance, many of the dynamic models do not match the data that was provided by Generator Owners (GOs), many models are incorrectly parameterized and unusable, or are wrong entirely. Investigation of several recent large disturbance events (e.g., the Blue Cut Fire) showed that multiple inverters tripped instantaneously based on what was supposed to be “instantaneous frequency” measurements, a topic explored elsewhere in this document. It is also worth noting that the majority of inverters were configured to momentarily cease current injection for voltages above 1.1 per unit or below 0.9 per unit (NERC 2017a, 2019). This operating mode is known as Momentary Cessation (MC) – an inverter operating state where the power electronic “firing

[1] P2800 - Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems (https://standards.ieee.org/project/2800.html)

commands" are blocked and result in zero active and reactive current output (NERC 2018, Zhu 2018). It was identified that only a few of the dynamic models used in the WECC base case accurately represented MC behavior in stability studies (NERC 2020a).

Currently, there are two major reliability standards defining the process of generator model verification and validation: NERC MOD-026-1 (NERC 2014a) and MOD-027-1 (NERC 2014b). These standards were primarily written for conventional synchronous generators and according to NERC report (NERC 2020a) the test activities based on these standards "are not adequately verifying the dynamic models relative to actual installed equipment performance for large disturbance response, leading to false expectations that these models are actually representative of installed performance."

NERC also found that "stability issues during high-penetration inverter-based resource conditions not easily detectible using positive sequence stability simulations" (NERC 2020a). Therefore, there is a need for improved and validated positive sequence models. Advanced EMT-based modeling will play more and more important role for stability studies in electrical grid areas with high concentration of IBRs (NERC 2020b). Based on the investigation of the recent IBR-involved disturbance events (e.g., Blue Cut Fire and Canyon 2 Fire) NERC found that Disturbance Monitoring and Reporting Requirements reliability standard (PRC-002-2) is "likely outdated with respect to the changing resource mix" (NERC 2020c). NERC recommends that all BES-connected IBRs should have high resolution disturbance monitoring data available (NERC 2020c).

IBR model validation studies are vital for proper representing of IBR dynamic behavior in BPS dynamic studies. The key component for successful model validation is having all required measurements. Several sources of data can be used for model validation: (1) The measurements from the real system (PMU or POW measurements), (2) Data from laboratory test equipment, (3) Data generated by real-time digital simulator (Opal-RT or RTDS), (4) from EMT simulations. Figure 19 shows an approach used in ERCOT for IBR model validation (Huang 2020). At the first stage EMT (PSCAD) model is validated against real IBR device lab testing and then the validated EMT model is used to benchmark RMS (PSS/E) dynamic models.

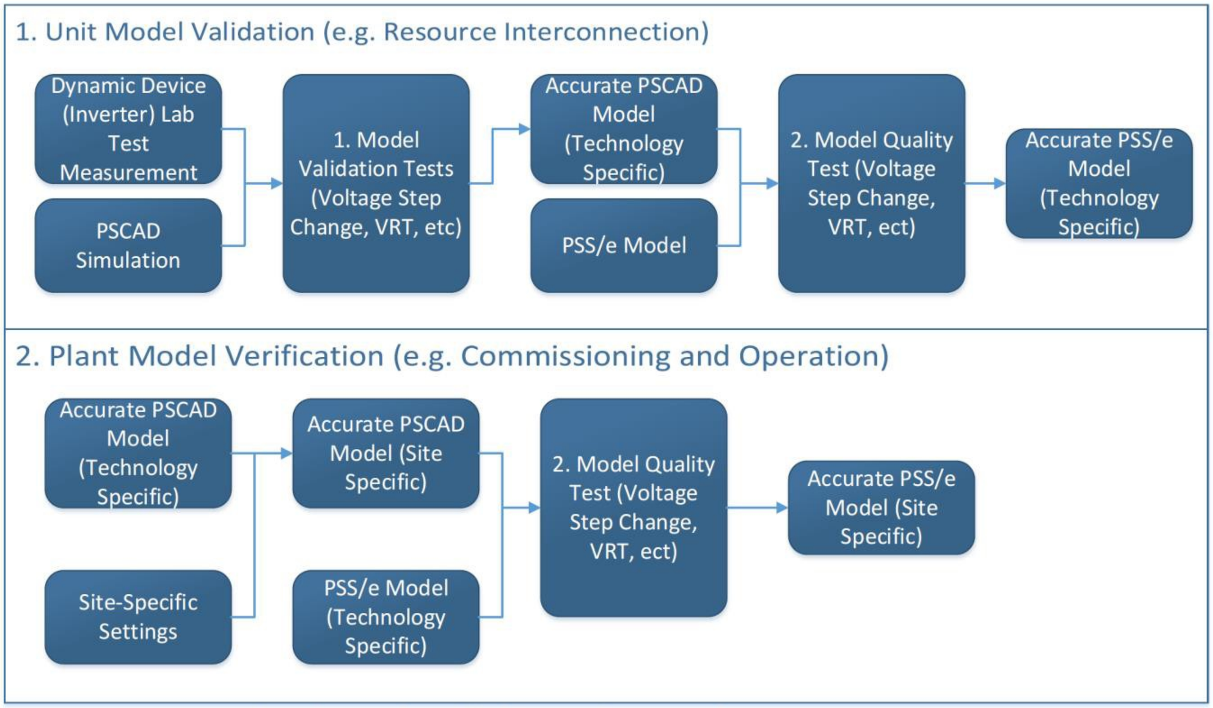

Figure 19 ERCOT model validation approach (Huang 2020)

Point on wave (POW) measurements of the actual power system events can be used for EMT and RMS model validation and having them is very important to validate IBR dynamic models. Power quality (PQ) monitors provide high resolution POW measurements (3 phase voltage and current) and they are used for the IBR monitoring by several electrical companies. For instance, HydroOne company from Ontario deployed more than 1000 PQ monitors and require PQ monitors installation on renewable generators bigger than 250 kW (Li 2019). PQ monitors help to identify various IBR issues providing event records for system-wide and local faults (Figure 20), plant level and individual inverters' fault response, detect abnormal IBR behavior and equipment malfunction.

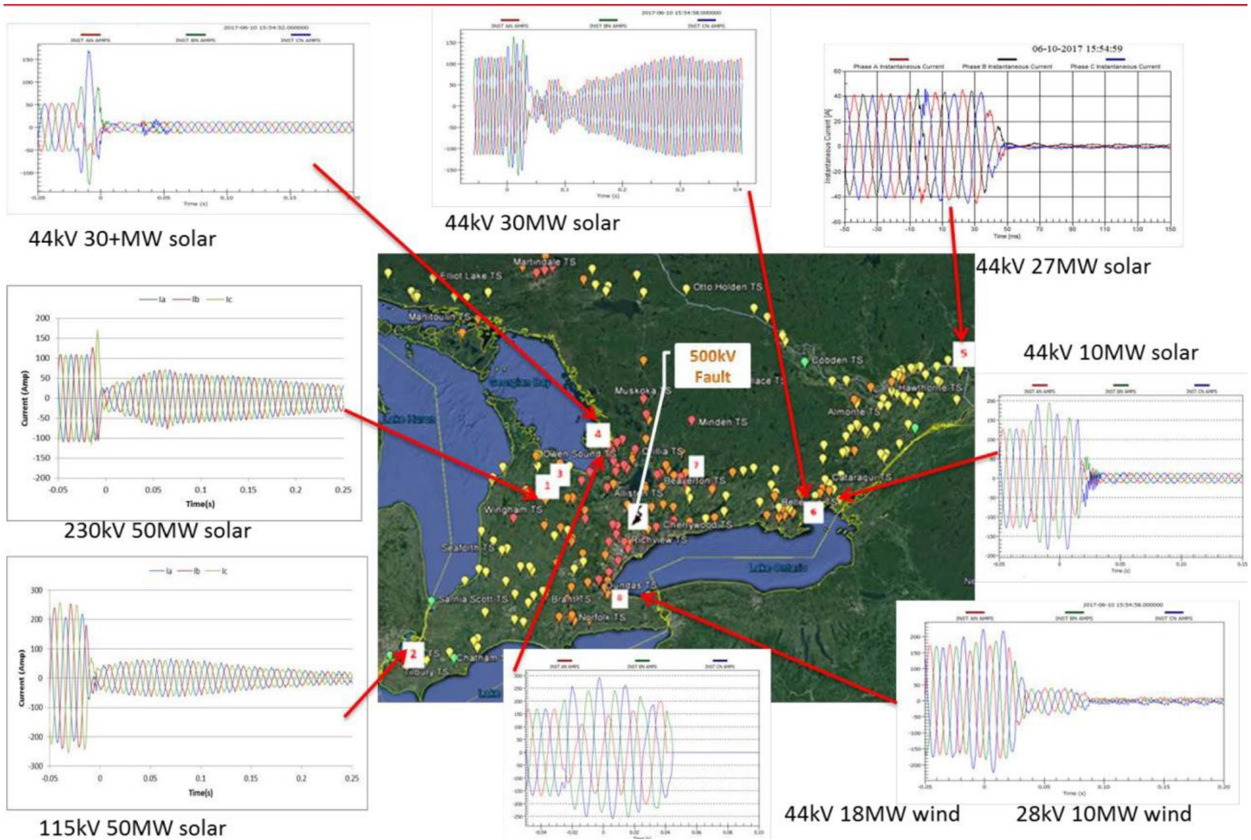

Figure 20 HydroOne renewable monitoring – system wide event (Li 2019).

Actual relay records for the fault response wind parks (Type-III wind generators) were used in (Haddadi et al. 2019) to validate generic wind generator models. It was shown that the generic wind plant model can adequately reproduce actual fault response, and wind park fault POW records can be used for validating EMT models, as in Figure 21.

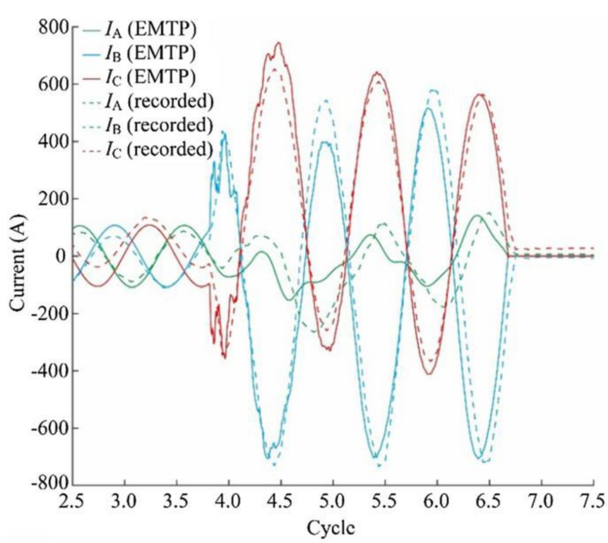

Figure 21 Wind park fault response: POW records vs. EMTP simulation (Haddadi et al. 2019)

Laboratory testing to study PV inverter behavior using the Blue Cut Fire Event voltage waveform measurements seen in Figure 22 collected during this disturbance were performed in (Mather et al. 2018). Laboratory testing setup is shown in Figure 23. POW measurements were played-in using Opal RT simulator. According to NERC PRC-024-2 standard (NERC 2013) generators must continue operation during off-nominal frequency periods caused by contingencies (Frequency ride-through capability). However, during the Blue Cut Fire event multiple PV generators were tripped by protection due to frequency miscalculation (NERC 2017a). Simulations in (Mather et al. 2018) have shown evidence that frequency protection mis-operation depends in part on the fault-induced phase shift. To perform the validation of the inverter models, it is important to collect not only the POW event records, but also PV inverter event logs and relevant data to identify the root cause of the inverter tripping (e.g., voltage protection, frequency protection or momentary cessation).

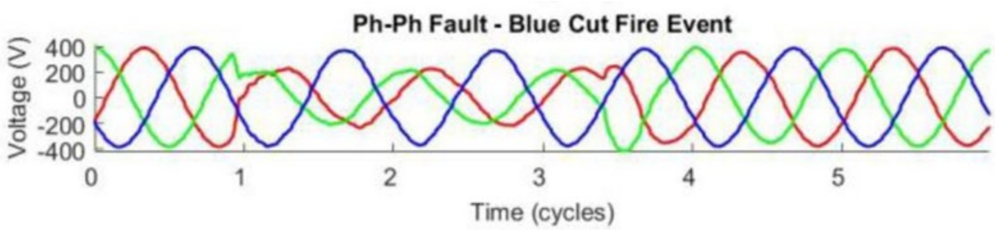

Figure 22 The Blue Cut Fire Event voltage records (Mather et al. 2018)

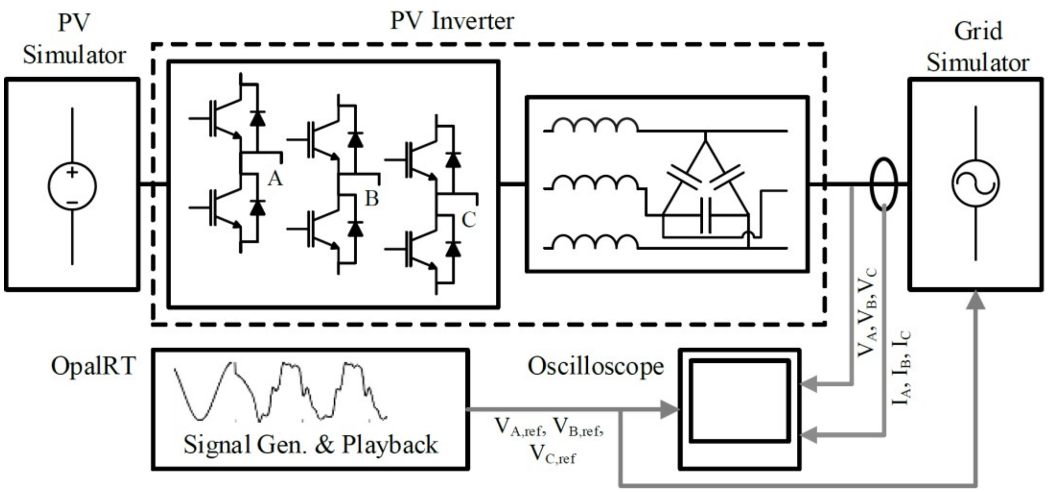

Figure 23 PV inverter laboratory testing setup (Mather et al. 2018)

One of the key findings in the recent NERC investigation on two big events with large amount of PV resources interruption (NERC 2019) is: “Lack of available high-speed data at multiple inverter-based resources has hindered event analysis. Some data was only time stamped with a resolution of one second or slower. This caused issues when trying to identify exact causes of inverter tripping.” To overcome this issue NERC recommends (NERC 2019): “Each inverter-based resource should have the capability to capture high speed data from some inverters within the plant during grid events”. Recommendations on the required IBR data collection for the purposes of disturbance monitoring, off-line event analysis, and post-mortem root cause analysis are provided in (NERC 2020c). The dataset should to include: (1) Control Settings and Static Values, (2) SCADA data, (3) sequence of events recorder (SER) data, (4) DFR data, (5) dynamic disturbance recording (DDR) data (e.g., PMU), and 6) Inverter Fault Codes and Dynamic Recordings. Collected information also needs to be time synchronized to a common time source, both within the plant and with external resources. Synchronization can be done using a GNSS clock or similar technology.

During the webinars hosted by the literature review team participants were asked several IBR-related questions. Majority of the survey participants expressed a great interest in IBR models validation and calibration. SCADA measurements are the most frequently used technology for IBR monitoring by electrical utilities. Survey results showed that PMUs, DFRs and PQ meters are also used, but less frequent compared to SCADA. The webinar participants also confirmed existing issues with the proprietary IBR models (provided as a "black box") could cause problems for model validation and inaccurate parameters settings.

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10.0 Discussion of Findings

Our survey has shown that while some practitioners do not fully understand the details and the theoretical aspects of the process of measurement, nevertheless many new uses for measurement are under consideration. The field is evidently far from static.

- There is support for the development of a more "capable" PMU. Performance limitations, particularly in terms of frequency response, limit the applications of the technology at present. There would seem to be no inherent reason why the performance could not be improved in this regard. It is likely that new algorithms and new documentary standards will be needed if the goal of interoperability is to be achieved.
- Point-on-wave technology would facilitate the development and implementation of schemes aimed at improved operation and protection. Communication system to support the data-flow that POW requires are available or in development, with latency values that meet the requirements of many applications.
- Power quality analysis has historically been concerned with assessment of how non-sinusoidal the delivered voltage is, measuring voltage sags and distortions. There is evidence that customer "satisfaction" is not greatly affected, but there is concern over light flicker. It is not clear that the matter of light flicker has been completely addressed since the advent of LED lighting and dimming technology. The measurement is operational, and that fact may not be fully understood.
- The power quality field is showing new promise in terms of utilizing the knowledge gained to identify some of the characteristics of these measurement results as signatures of particular interest. From the measurement point of view, this is particularly interesting as a departure from the modeling that has historically characterized power system measurements.
- Another aspect of measurement of potential value is the measurement of system parameters. These are normally regarded as fixed quantities, perhaps because we engineers are all brought up to visualize a linear time-invariant world. It is known that transmission line parameters are not perfectly constant—the resistance is, for example, temperature dependent. It is likely that both operations and planning would be improved if parameter value estimates could be routinely made.
- The PMU is being considered for application in the distribution system. One might imagine this is a long overdue step. The Westinghouse Electric Utility Engineering Reference Book on distribution systems, first published in 1959 begins with these words:

  > Broadly speaking, an electric power system can be defined to include a generating, a transmission, and a distribution system. The distribution system, on a national average, is roughly equal in capital investment to the generation facilities. The sum of these two generally constitute over 80 per cent of the total system investment. Thus, it is readily seen that the distribution system rates high in economic importance, and represents an investment that makes careful engineering, planning, design, construction, and operation most worthwhile.

  While those words are still likely true, the distribution system has not seen the same level of careful engineering, planning or design that characterizes the other two parts of the utility, and its operation has, for the most part, not been monitored with anything like the details of the transmission system. The addition of PMU technology would represent a big step forward.

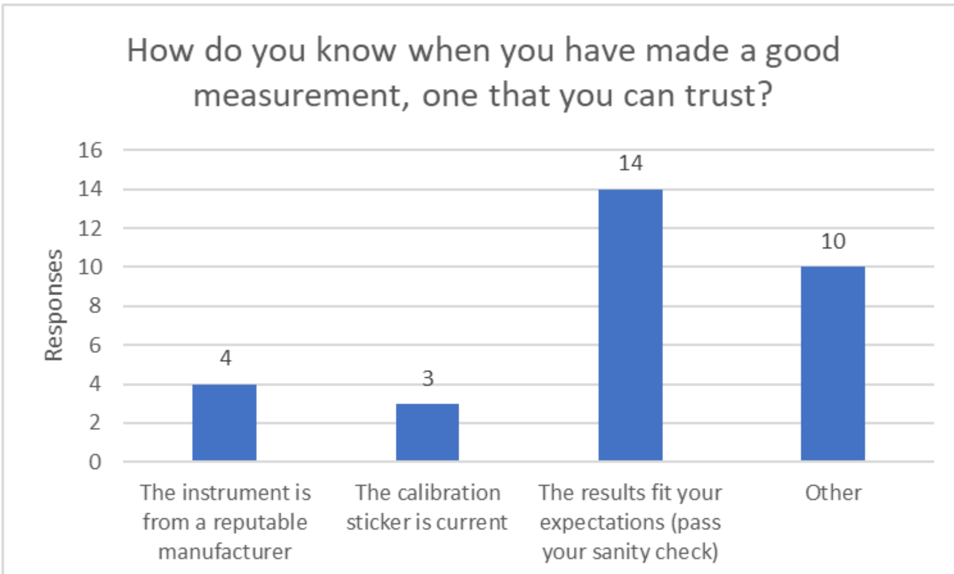
These various expansions of measurements will no doubt benefit from a better appreciation of the theoretical aspects of measurement. In this, and other, regards, our survey of the literature has identified gaps as well as possibilities.

In developing our roadmap, we conclude that DOE should be made aware of the gaps as well as the exciting new areas for the application of measurements. The gaps are the subject of the next major Section of this Report.

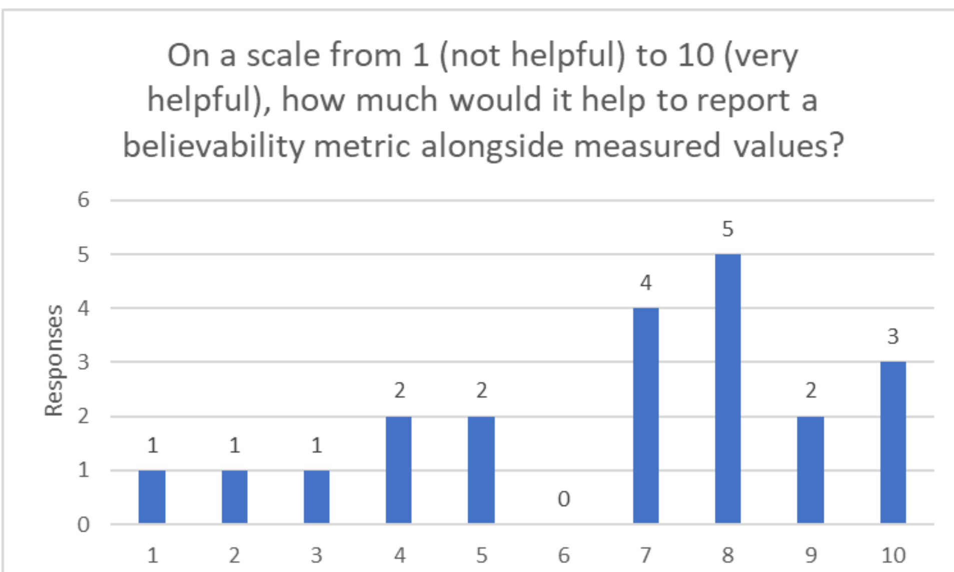
Appendix A – Webinar Questions

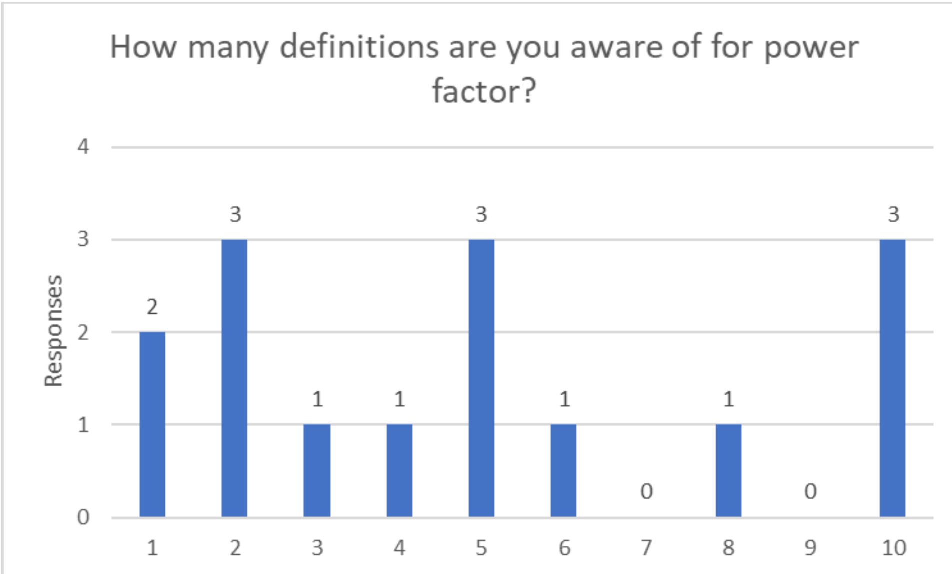
This appendix contains the raw results from the webinars PNNL hosted to receive input from stakeholders. The following subsections correspond to the sections of the webinars.

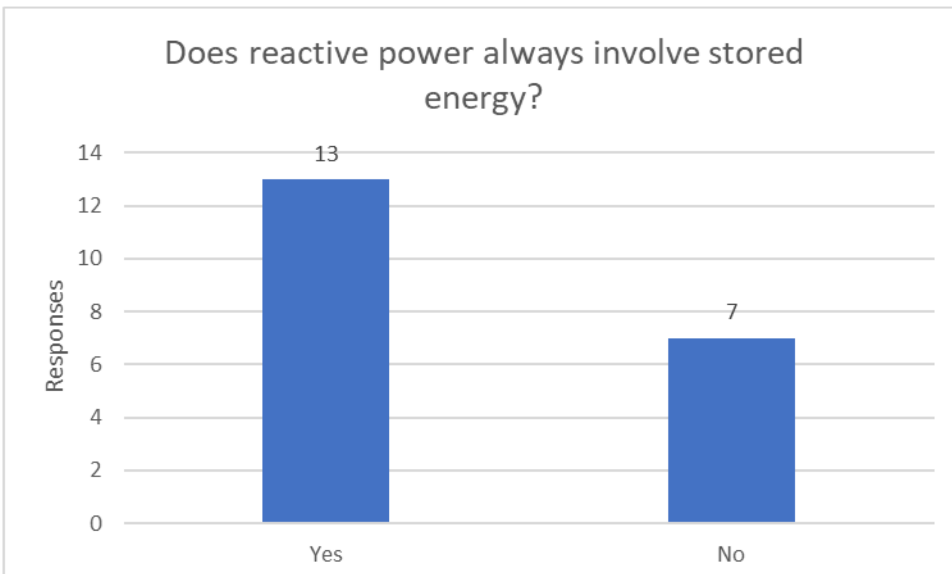
A.1 Measurement

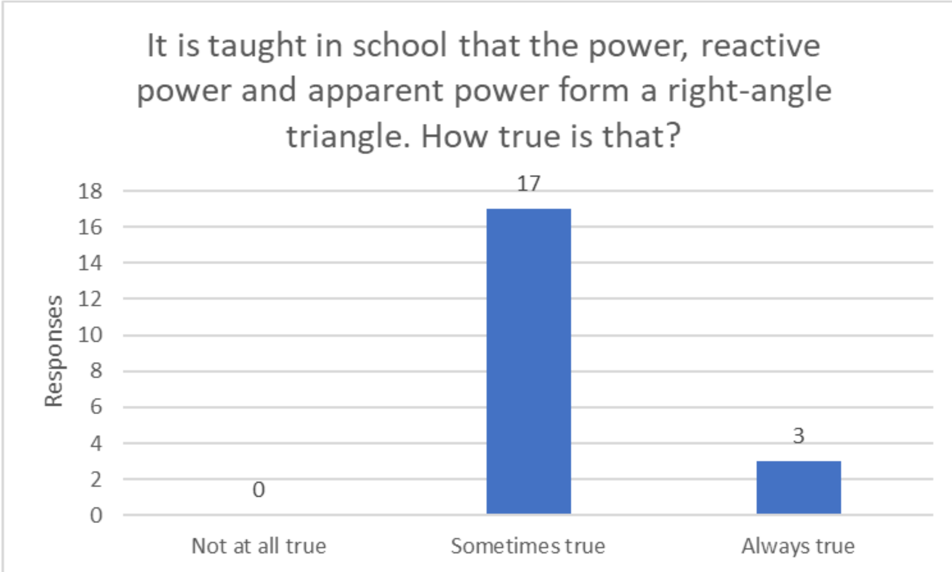


One participant that responded “Other” suggested that the instrument must meet a standard.

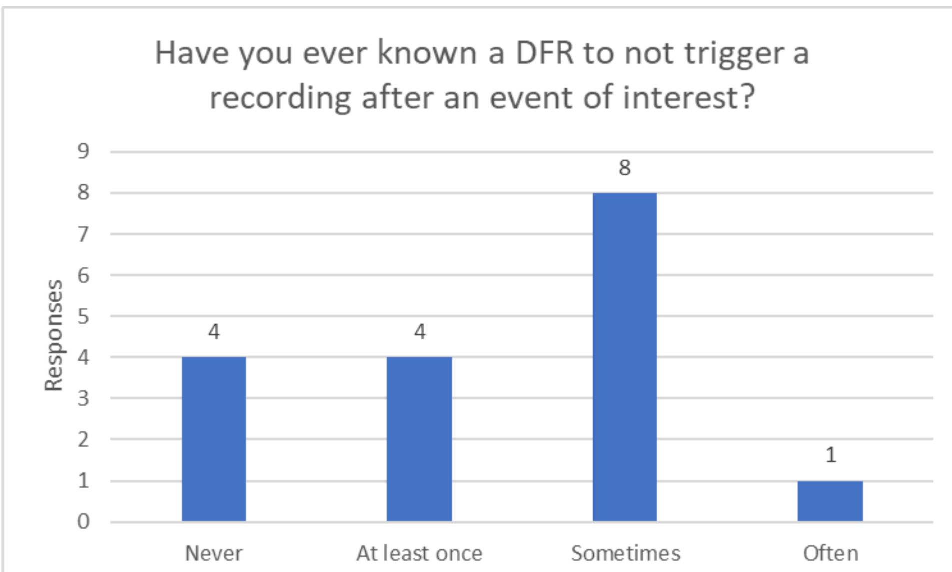


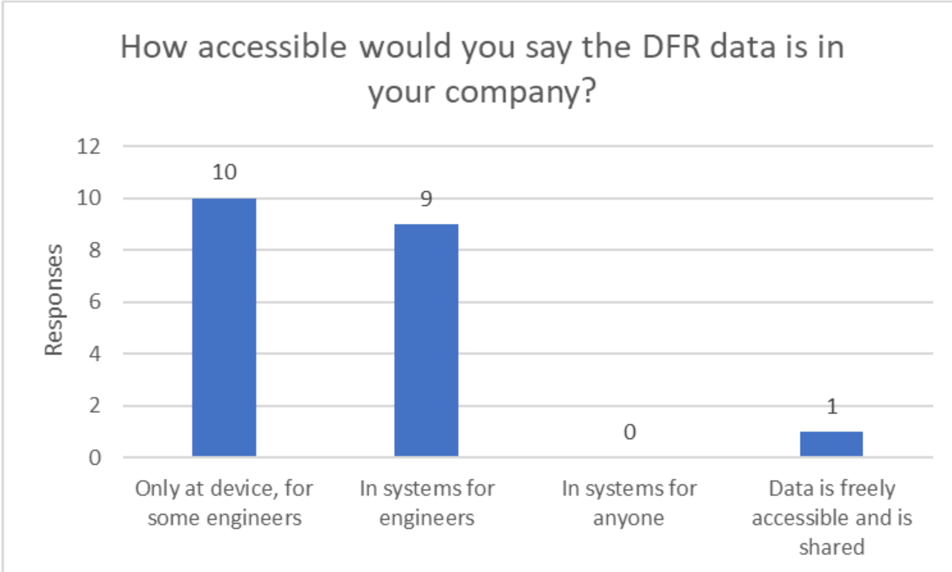

How many definitions are you aware of for power factor?
Responses
4
3
2
1
0
2
3
1
1
3
1
0
1
0
3
1
2
3
4
5
6
7
8
9
10

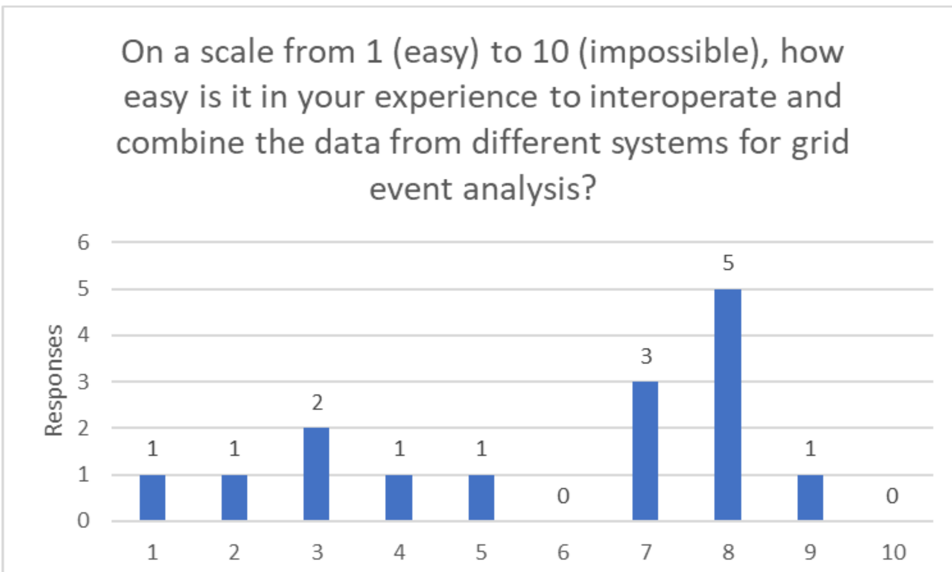

Does reactive power always involve stored energy?
Responses
14
12
10
8
6
4
2
0
13
7
Yes
No



A.2 Power Quality, Digital Fault Recorders, and Phasor Measurement Units



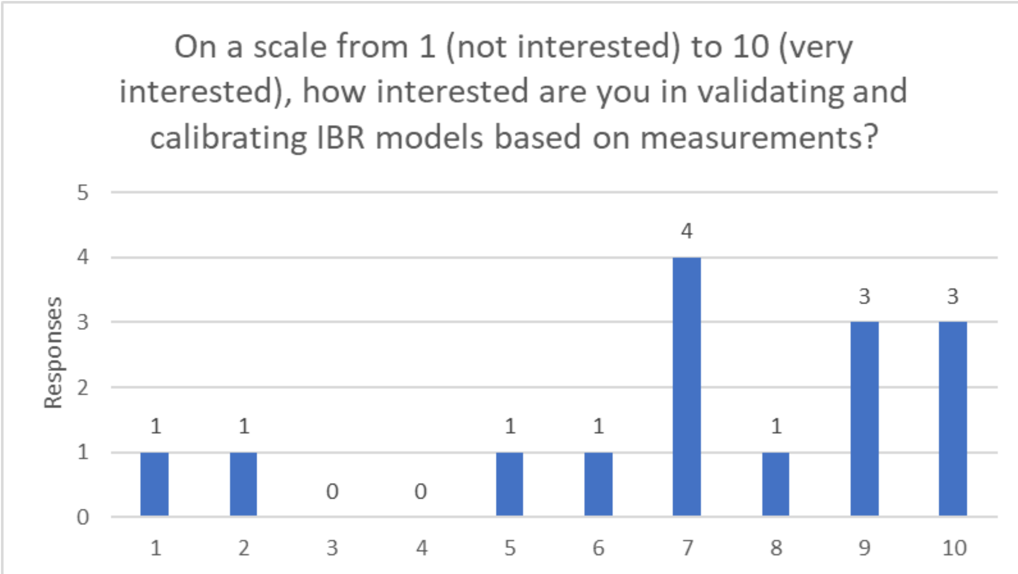


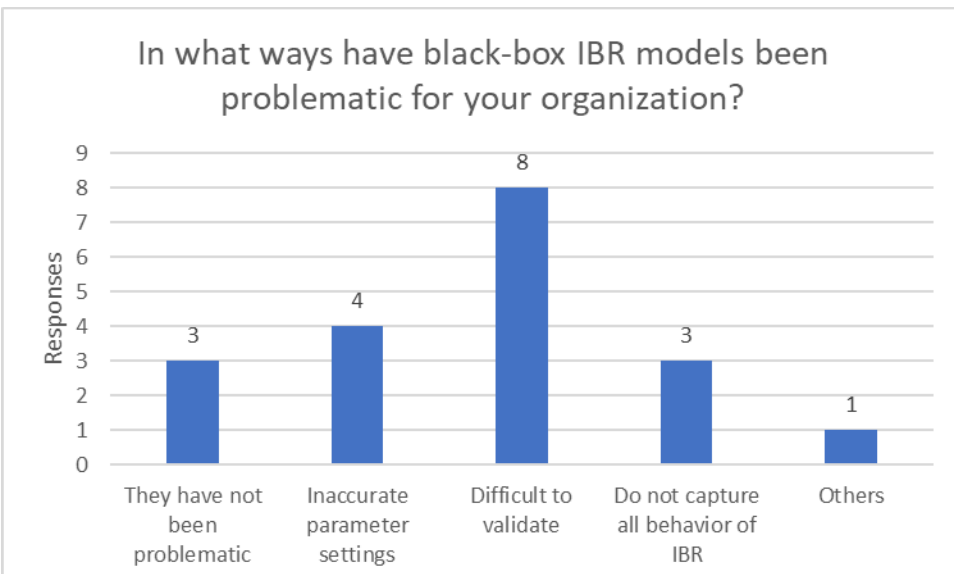


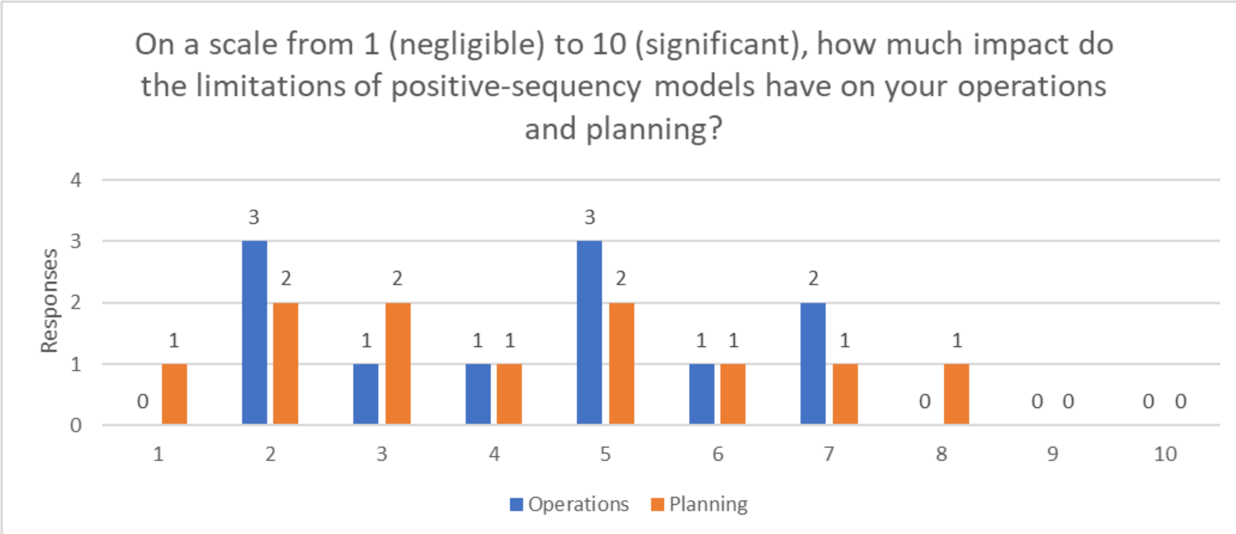
Discussion questions:

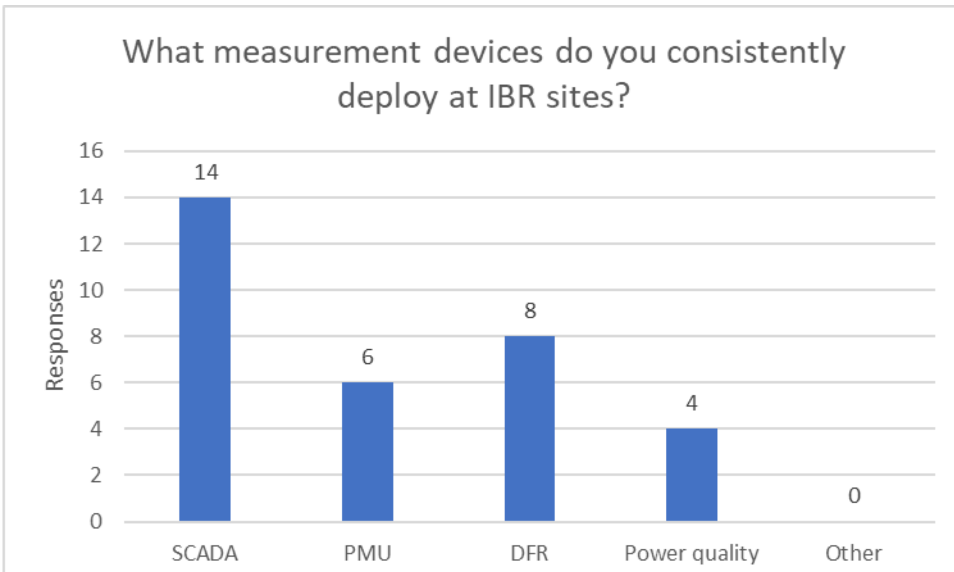
- What are creative ways that your organization has used power quality or digital fault recorder data?
- What are some potential ways that power quality or digital fault recorder data could be used?
- Do you see obstacles that don't allow power quality or digital fault recorder data to be used more extensively and universally?

A.3 Inverter-Based Resource Models



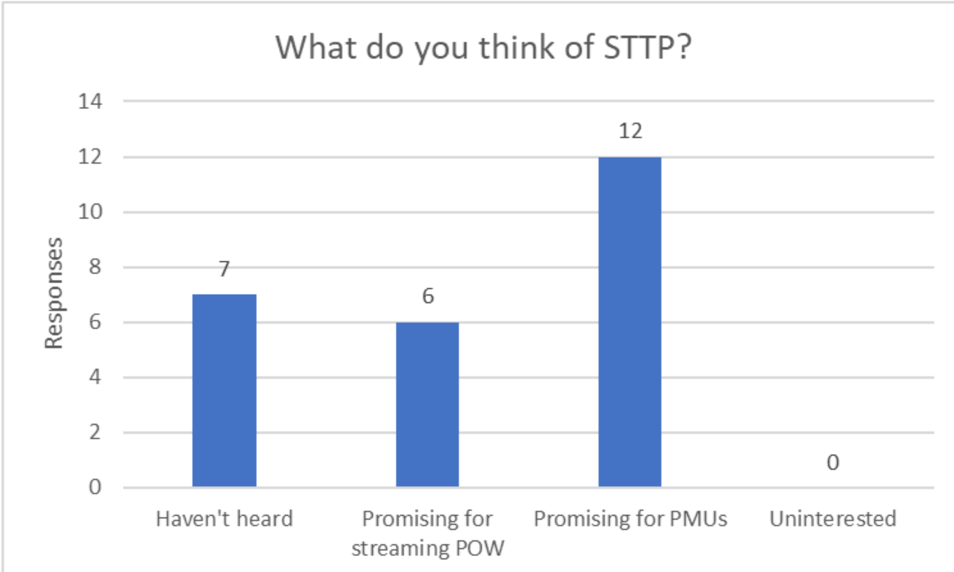


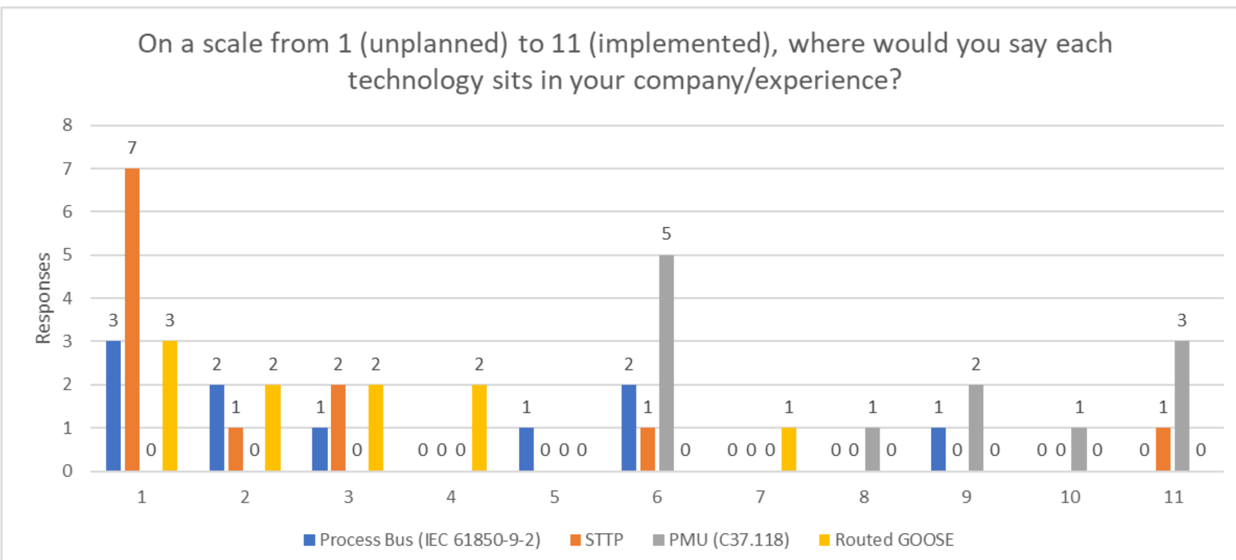


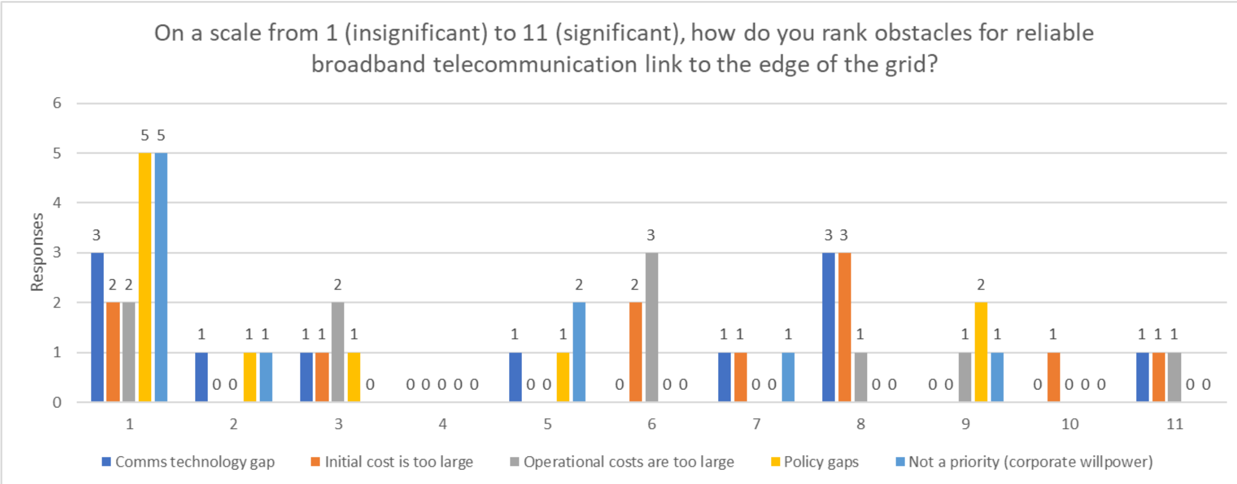


Discussion question: What new regulations, standards, or policies regarding inverter-based resource monitoring would you like to see?

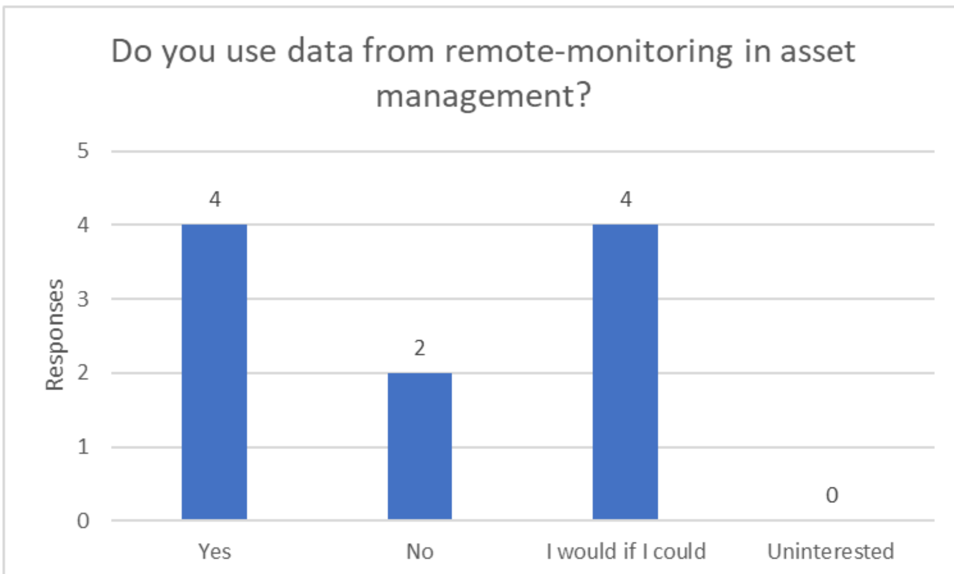
A.4 Communications

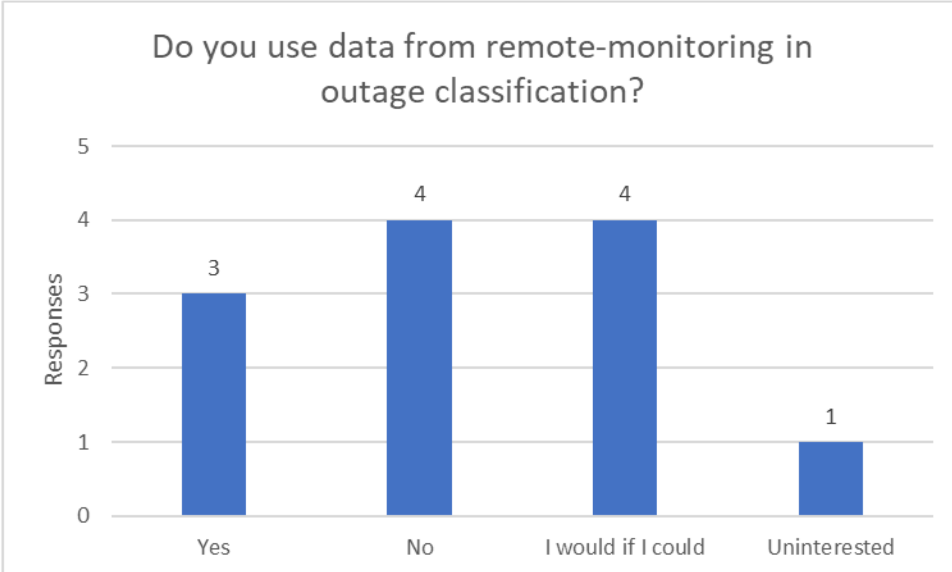


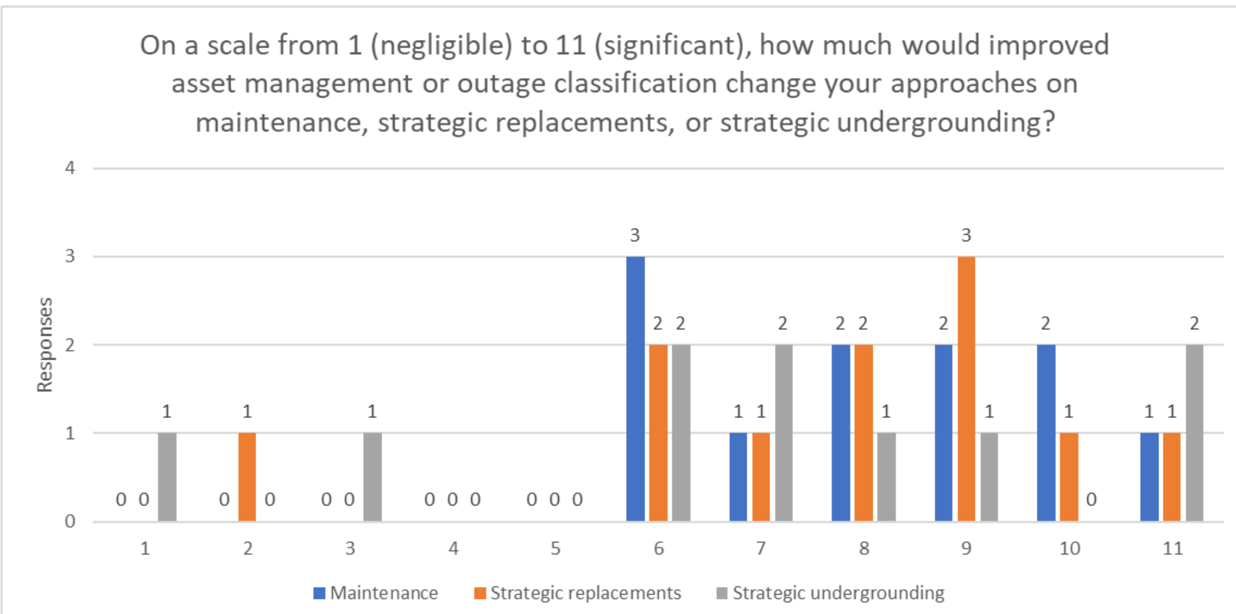




A.5 Asset Management and Outage Classification







What types of outages are most vulnerable for being misclassified because of missing/unreliable measurements?

- Common mode and dependent type of outages
- Lightning related
- Tree related
- Fuse failures
- Recloser failures
- Pole-top (distribution) transformer issues
- Intermittent line issues (especially during high-wind or storm conditions)

- Frequency excursions and voltage dips being mistaken as outages

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