Case Study: Phasor-Based Control for Managing Inverter Generation

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***Abstract*—This paper reviews the implementation of phasor-based control systems for inverter generation facilities. Instead of using traditional supervisory control and data acquisition (SCADA)-based protocols, which have data update rates of 1–5 s, this power plant controller used phasor-based measurements to implement real power, voltage, volt-ampere reactive (VAR), and power factor (PF) controls. Because phasors offer substantially faster data updates, the site could implement traditional generation management functionality with faster response and greater stability. This paper covers the following major categories:**

- **How technology was utilized to implement this functionality and how it compares to traditional power plant control systems**
- **How using phasor-based controls improved several applications, including voltage regulation and frequency response**
- **How generation facilities benefit using phasor-based control**

I. Introduction

Many inverter-based generation facilities for photovoltaic (PV), wind, and batteries use communication protocols like DNP3/Modbus to manage set points for the inverters and receive the collective feedback signal from a point of common coupling (PCC) or point of interconnect (POI). The speed and responsiveness of the controller is significantly affected by how quickly these communication systems are able to provide measurement updates to the controller. In many circumstances, data that updates between one and several seconds are good enough to manage the inverter generation facility. If information were available in tens or hundreds of milliseconds to the plant controller, a faster and more accurate response from the inverter generation facility is achieved. This faster and more accurate response allows the generation facility to achieve the following objectives:

- Compliance with the most stringent of grid codes
- Participation in energy markets and services with strict performance requirements, such as fast frequency response (FFR)
- Validation of asset dynamic models, such as NERC MOD

For the plant controller to receive data updates in tens or hundreds of milliseconds, the IEEE C37.118 synchrophasor protocol is used. This high-speed protocol allows the previously mentioned objectives to be met, but this protocol has different infrastructure requirements than traditionally used DNP3/ Modbus protocols.

This paper covers the differences between a phasor-based control system vs. one that uses DNP3/Modbus in the following ways:

- Differences between the infrastructure and technology
- Differences between DNP3/Modbus and phasor data for input to control algorithms
- Performance of phasor-based control systems for typical power plant systems, such as voltage regulation and frequency response

II. Usage of Phasor-Based Control Systems and its Benefits

Phasor-based control systems have been developed for utility scale and distributed energy resource (DER) renewables, battery storage, controllable loads (e.g., hydrogen electrolysis), and their combinations. Control systems scale to many applications as well. The authors of this paper have implemented synchrophasor-based control with a total capacity of more than 2 GW in multiple PV and battery storage sites in the Electric Reliability Council of Texas (ERCOT), California Independent System Operator (CAISO), PJM Interconnection, and Alberta Electric System Operator (AESO) service territories. These sites have wide-capacity ranges. The largest phasor-controlled facility implemented by the authors is a solar plant (497 MW) in ERCOT. The smallest installation is a 2.5 MW DER.

Control system performance requirements for renewable generators are becoming more stringent, reflecting increased grid penetration of renewable energy. For example, AEMO and Western Power [2] require non-synchronous generator rise time for the controlled voltage or reactive power output to be within 1.5 s. Participating in potentially lucrative ISO/RTO current and future services (e.g., ERCOT and FFR) requires adequate control system performance. Current ERCOT Nodal Protocols specify that the “obligated response within 15 cycles after frequency meets or drops below a preset threshold” [4].

Because of increased revenue opportunities, phasor-based control now includes regulation and frequency markets, DER energy market participation, demand response participation, and revenue from excess green electricity. Synchrophasors improve seamless islanding and reconnection to the main grid with multiple DERs.

III. Communications Architecture Comparison

After comparing communication architectures for phasor-based systems with traditional plant control architectures, there are three areas of focus.

- Communication medium (serial, Ethernet, fiber) and communication protocol
- Data update rates and bandwidth
- Time synchronization and accuracy

For each of these categories, DNP3/Modbus communication methods can operate on the full spectrum of communication designs. Phasor-based systems have specific design criteria: Ethernet networks, high-accuracy time synchronization, and high-bandwidth capabilities for fast data updates. For traditional PV plant control, the most common communications often include Modbus EIA-485 communications, which share multiple inverters on a single communications circuit. This communication architecture has a low cost compared to other alternatives; it is relatively simple and polls information to the plant controller in 1–5 s intervals. Communication to the PCC/POI may look a bit different using DNP3 or Modbus over an EIA RS-232 or Ethernet-based connection, but the data update rate is not often different than the standard 1–5 s. This is sufficient for data reporting and sending real and reactive power set points for inverter generation at most facilities.

Phasor-based systems exchange data at a significantly faster rate. Update rates often occur between 16 ms to 100 ms intervals depending upon the configuration. This increased requirement in bandwidth cannot be achieved on EIA-485 multidrop/party lines. It is difficult to configure via direct RS-232 links. This requires usage of an Ethernet communication network to allow for the bandwidth that synchrophasors require.

Phasors require time synchronization between each device so that a device that processes the phasors can align the data and process the information from the different devices. The required time synchronization is 1 µs or more. There are only a few protocols and methods that offer this level of time accuracy. For power system applications, this is typically the IRIG-B and IEEE 1518 Precise Time Protocol (PTP). Both are generated from a clock that takes a GPS signal and translates it into the protocol format. IRIG-B is typically distributed via a coaxial network, and IEEE 1518 PTP is distributed via an Ethernet-based network. Based on the design and capabilities of the Ethernet network, the same infrastructure for phasors and PTP may be shared. Intelligent electronic devices (IEDs) at a solar farm with traditional communication infrastructure are unlikely to be time-synchronized together via a high-accuracy time signal like IRIG-B or IEEE 1518 PTP. The device at the PCC or POI might be a revenue grade meter or protective relay with some time synchronization for revenue billing or Sequence of Events (SOE) recordings, but it might not have accuracy better than 1 µs.

IV. Example of Synchrophasor Communication Architecture Implementation

In the applications covered in this paper, the following communication architecture has been used for phasor-based control systems. The PCC is primarily monitored by a revenue grade meter, which provides an IEEE C37.118 synchrophasor stream to the power plant controller. The PCC also has a protective relay that provides a backup or redundant IEEE C37.118 synchrophasor stream to the power plant automation controller.

The power plant controller communicates with inverters via the Modbus Transmission Control Protocol (TCP). The necessary speed for control algorithm feedback primarily comes from the PCC or the aggregation point of cumulative inverter output, where it is important for the information updates to be quick with synchrophasor technology. While it would be beneficial for inverters to support higher speed communications, most inverters do not support this, and DNP3/Modbus for control set points are sufficient in speed for control. The feedback from individual inverters is typically used to determine if an inverter is responding to its given set point or has a reduced capacity. The plant controller sends all phasor measurement unit (PMU) data to a phasor data concentrator (PDC) to archive data from the plant controller.

The revenue grade meter, protective relay, PDC, and inverters all communicate via an Ethernet local-area network (LAN). All devices, except the inverters, are synchronized to IRIG-B from a GPS clock that provides time synchronization with accuracy better than 1 µs (see Fig. 2).

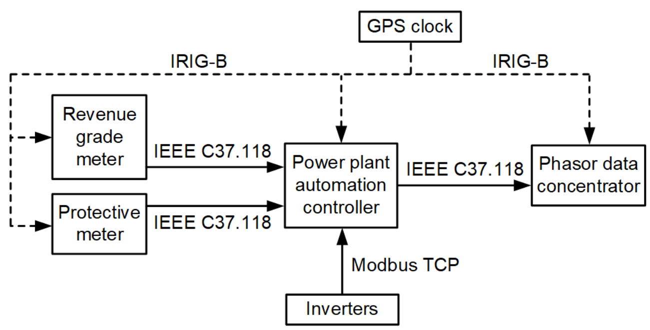

Fig. 1. Example of phasor communication architecture for power plant control

V. Importance of Phasor Data and Latency Time Alignment in Data Delivery

A phasor is represented by the equation shown in (1), defined by the IEEE C37.118 standard [1].

$$X = X_r + jX_i = \left(\frac{X_m}{\sqrt{2}}\right)e^{j\phi} = \frac{X_m}{\sqrt{2}}(\cos\phi + j\sin\phi) \quad (1)$$

The measurement includes a magnitude and associated phase angle. When comparing two measured points from different devices, it is important that the calculations are able to operate on data points with the same phase angle. A time error of 1 µs between two devices would correspond to 0.022 of a phase angle difference [1]. The total vector error between two devices, as defined by the IEEE C37.118 standard, reaches

1 percent when the phase angle difference is 0.57 degrees [1]. This corresponds to a time difference of 26 µs between two devices. For phasors to be used in a central location and process the data, it is important that each device is time synchronized accurately. This helps highlight the importance of high time accuracy in devices producing these phasor measurements.

The other important aspect of phasor data is the latency of time in which it is delivered from the originating device to the processing device. Phasor data are measured on a regular interval; if a processing device does not receive the measured data on a similarly mimicked window, then it is difficult for those data to be used in real-time control applications (e.g., a system that generates data at 60 messages per second). This occurs approximately every 16.67 ms. If a device only transmits the data every 50 ms and packages three measurements together, the phasor processor device is only able to operate on the latest data. If one PMU transmits data less frequently, with multiple packets together, and another PMU publishes data on the interval when it takes the measurement, then the processing device is effectively making control decisions at the rate of the data-bundling PMU. Likewise, if all PMUs transmit data on the correct interval, but the network introduces more than a few milliseconds of latency, the control device is in the same situation as the device that publishes data late. The controller is unable to make decisions in real time when data are published or received late. This is different from a device that is designed to archive or concentrate phasor data. Since the purpose of that device is to record data, it has the ability to handle latency and delays in data arrivals differently than a controller, which is designed to make real-time decisions. Because of this key difference, it is important that in phasor control plant architecture, the network has low latency to ensure the timely delivery of phasor data.

VI. Differences in Phasor vs. SCADA Data for Control Algorithms

Data that is typically collected over DNP3 or Modbus for inverters and meters for power, voltage, current are root-mean square (rms) measured values. To calculate, rms value data are squared, summed over a number of power system cycles, divided by the total number of samples, and then taken by the square root. The mathematical representation is shown in (2). The result of this calculation provides the quantity that is typically reported via DNP3 or Modbus. There are variations on rms based upon the number of cycles those data are averaged over and the number of samples in a cycle. There may also be some difference between devices if the fundamental frequency is used or if additional harmonics are included in the rms calculation. Standard bodies do provide some guidance on recommendations for these values. For example, IEC 61000-4-30 defines Class A rms measurements to be the sum of a sample rate over the course of 12 cycles (~83.33 ms) [3]. Depending on the device, these rms signals may have some interval in which the device makes new quantities available for communication interfaces. A device may be polled via DNP3 or Modbus once every 100 ms but may only provide new rms values every 500 ms or 1 s.

$$Xx = \sqrt{\frac{\sum_0^{N-1}\left[s(n)\right]^2}{N}} \tag{2}$$

where:

N = total number of samples

n = index number

s(n) = corresponding power system value for a given index

Xx = calculated rms for a power system value

The synchrophasor data are vectors that contain a magnitude and an angle for each time-stamped measurement. These measurements are not point-on-wave angles. The magnitude portion of that measurement is also an rms calculated quantity. The angle is the instantaneous phase angle relative to a cosine function at the defined time-synchronized system frequency [1]. There are applications for both the magnitude and phase angle of the synchrophasor. But for phasor-based generation control, only the magnitude of the synchrophasor can be used like the value from DNP3/Modbus protocols to the control algorithms. This is because the control algorithms for managing inverter generation do not need phase angle information. Synchrophasor data update significantly faster than DNP3/Modbus data and may show more noise in the signals. In this case, a filter can be used to clean up any noise before passing it into the same control algorithms that were used with DNP3/Modbus data. Due to minor behavioral differences in the data of synchrophasor and SCADA protocol magnitudes, it is an easy transition from logic processing between these two data sources. The control algorithms do not need to change, but the frequency of control algorithms being executed does need to change.

VII. Differences Between C37.118 Standards

The IEEE C37.118 standard has gone through several revisions. Most changes in the standards have been related to testing and performance guidelines. However, among IEEE C37.118-2005, IEEE C37.118.1, and IEEE C37.118.2, the formal definition of synchrophasor had changed [5]. In IEEE C37.118-2005, the phasor was assumed to have a reference phase angle of zero degrees at the top of the second [5]. This definition worked well for signals that were in a steady state. There was concern that signals that change quickly during the measurement process may not be represented accurately enough [5]. Previously, a phasor was defined in terms of fixed frequency that is common to all phasors in analysis for each measurement. IEEE C37.118.1-2011 now removed the fixed nominal frequency and analyzed the signal changes as a dynamic phase angle function [5]. Depending on the application signal, this difference may lead to more variances in signal from sample to sample. This may be easiest to see in frequency measurements.

Depending on the usage of the data, the difference in this sampling may equate to more noise in a signal. For example, in Fig. 2, the orange line represents frequency measurements with IEEE C37.118.1-2011, and the blue line represents the same frequency measurement with IEEE C37.118-2005.

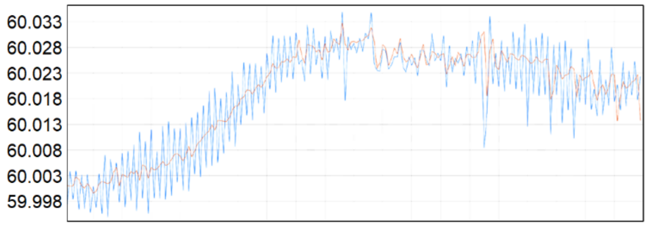

Fig. 2. Frequency measurements in IEEE C37.118.1-2011 (orange) vs. IEEE C37.118.2005 (blue)

If devices implement different versions of the IEEE C37.118 standard, data from recent standards might require running through a low-pass filter prior to passing the data to the control algorithm.

VIII. How Inverter-Based Controls Benefit From Phasors

Phasor-based controls primarily benefit control systems by providing quick updates so that the control algorithms—specifically, the proportional integral (PI) controllers—can run frequently. With a phasor rate of 30 messages per second and data updates approximately every 33 ms, the PI controller can comfortably execute five to ten times faster than a DNP3/Modbus connection, which provides data updates once per second. This difference between the calculation of set points and feedback leads to a faster and more accurate response. Therefore, a PI controller, which receives faster feedback and executes more often, is able to generate a faster and more accurate result. The question here about phasors is not about how usable it is but how much faster and more accurate the application results are. It is difficult to say that all facilities that use phasors at a specific message rate will achieve a specific performance rate. There are many factors that affect the end performance of the system, including the communications system delivering set points quickly, ramp rates at the PCC/POI, ramp rates at the inverters, and individual inverters responding to set points—much more than controlling logic set points that contribute to the response of the system. However, in a test environment where all of these factors remain constant (except for the feedback signal rate and the execution rate of the controller), we can establish an expected performance comparison between the update rates of synchrophasors and DNP3/Modbus. The following data are generated by a simulated test system with the following characteristics:

- 100 inverters
- Real power rating = 733 kW
- Reactive power rating = 325 kVAR
- Zero ramp rate restrictions at POI/PCC
- Zero ramp rate restrictions on inverters
- Inverters respond to set points within 100 ms
- Modbus TCP connection to each inverter
- Nominal voltage of 140 kV at PCC/POI

The test case is a 3 kV voltage change from 139 kV to 142 kV. To achieve this voltage change, an injection of approximately 24.8 MVAR is necessary into the system. At 139 kV, the PCC/POI sees a consumption of approximately 6.3 MVAR; at 142 kV, the system produces approximately 18.5 MVAR. Fig. 3 shows the response of a 1 s update from the PCC using Modbus. It is important to note that the x-axis in Fig. 3 is in absolute time. The PI controller also executes at the same data rate. To obtain a system response of about 23 s, the controller has a small amount of overshooting that settles quickly.

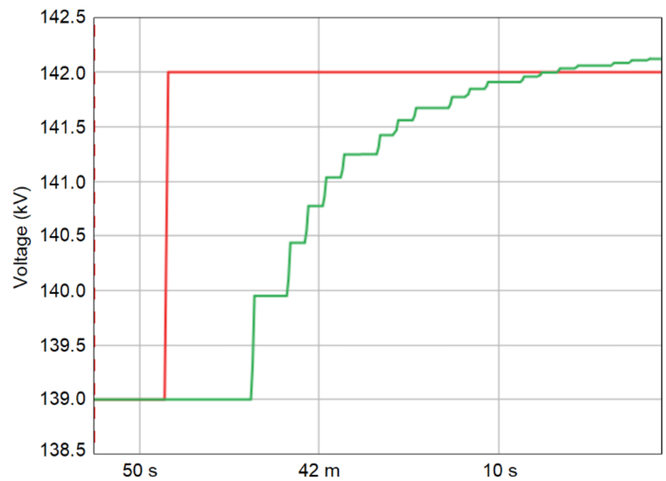

Fig. 3. 1 s data update with a 3 kV voltage response

Fig. 4 shows a response of a 100 ms (10 messages per second) update rate from the PCC using synchrophasors. It is important to note that the x-axis in Fig. 4 is in absolute time. The PI controller executes at the data update rate. In this case, the response time from the set point change is about 5 s. There is no overshoot, and the response is very smooth.

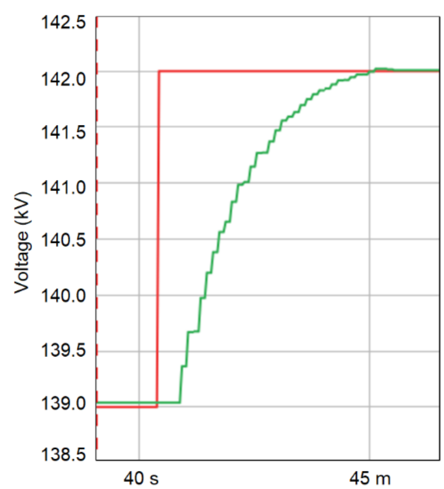

Fig. 4. 100 ms data update with 3 kV voltage response

The difference between a system that updates at 1 s vs. 100 ms is more than five times improved in response time. While this simulated test has nearly ideal conditions to produce very quick responses for large system swings, the important takeaway is not the individual response time of each test but the relationship between the two. A phasor-based control system has a factor of five times greater. It updates in 100 ms compared to 1 s updates from DNP/Modbus. This is a significant improvement in system response. The next case looks at a response from an in-service facility using synchrophasors. This case focuses on a 100 MW facility connected to a 138 kV transmission line. Fig. 5 illustrates an automatic voltage regulator (AVR) test. Stepping up the voltage set point by approximately 3 kV (see Fig. 5c in line-to-line voltage) causes the AVR, which is configured with 5 percent reactive droop to smoothly increase reactive injection by 23 MVAR (see Fig. 5a) in approximately 15 s with no overshoot and a very accurate response. The voltage response (Fig. 5b in line-to-neutral voltage) matches the reactive power response.

Fig. 5a

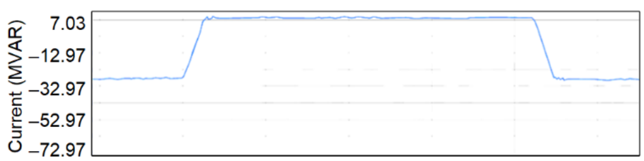

Fig. 5b

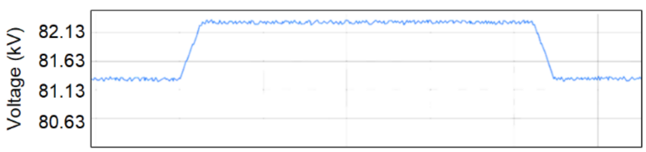

Fig. 5c

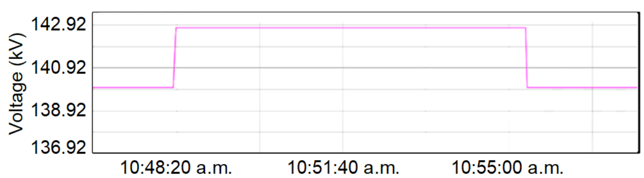

Fig. 5. Phasor voltage response

Phasors not only allow set point changes to execute quickly and accurately but also respond to changing system conditions rapidly.

Fig. 6 illustrates a primary frequency response (PFR) test from the same 100 MW facility. Stepping up the frequency reference from 60 Hz to 60.2 Hz causes the controller to decrease active power generation by approximately 6 MW in less than 7 s, bringing the frequency back to 60 Hz.

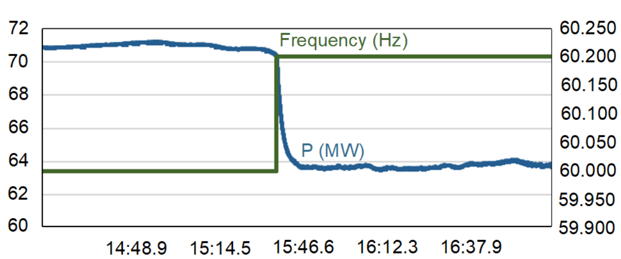

Fig. 6. Phasor frequency response

IX. Conclusion

This paper has discussed the differences between traditional PV plant control communication architectures and phasor-based control. There are strict time-synchronization accuracy, bandwidth, and communication network requirements for phasor control, but with this capability, the speed, accuracy, and responsiveness of phasor inverter generation control is increased by more than a factor of five. This is a significant benefit for systems that participate in energy markets where the speed and accuracy of responses enable those facilities to participate in services with the International Organization for Standardization (ISO) that require it. Because of the performance benefits using phasor-based control, users should consider implementing it in more generation plant installations.

X. References

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XI. Biographies

Dmitriy Anichkov is chief technology officer of Merit SI, LLC, with more than 30 years of global engineering and management experience in the power industry. Dmitriy developed energy management and control systems, serving GDF Suez (currently known as ENGIE), Alstom Grid, MISO Engineering, Duke Energy, and others. He possesses a wide range of experience in research and development, commissioning, and operations.

Brian Waldron is a development lead automation engineer with Schweitzer Engineering Laboratories, Inc. (SEL) in Pullman, Washington. He has several years of experience in designing and troubleshooting automation systems and communications networks. He has authored several technical papers and application guides, and has taught presentations that focus on integrating automation products. Brian graduated from Gonzaga University with a BS degree in electrical engineering.

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