The Use of Negative Sequence Quantities in Protective Relaying

Negative sequence quantities originate from the theory of Symmetrical Components developed by Charles Fortescue in 1918. This theory states that an unsymmetrical set of phasors can be decomposed into one unsymmetrical but equal set of three phasors (zero sequence) and two symmetrical sets of phasors (positive and negative sequence).

Positive sequence quantities are found in all fault types as well as normal system operation. Negative sequence quantities are found in line-line (LL) and line-ground (LG) faults. Zero sequence quantities are found only in line to ground faults.

**Figure A** illustrates an A-Ground fault. Note the presence of all sequence networks and that all sequence currents for A phase are aligned.

**Figure B** illustrates a B-C phase fault. Notice that using superposition, A phase quantities cancel out and B and C phase quantities sum to their fault current magnitude. Also note that zero sequence currents are not present.

**Figure C** represents a balanced 3 phase fault. This phasor diagram could also represent normal balance load conditions. Note that neither negative nor zero sequence quantities are present.

![Phasor diagrams for A-Ground, B-C, and ABC faults.](image)

Traditionally, in overcurrent protection, zero sequence quantities are used to detect the ground faults illustrated in Figure A. Zero sequence quantities offer a secure and reliable means for detecting ground faults. Positive sequence currents are typically used for the three phase and LL faults illustrated in Figures B and C. Positive sequence phase pickup current must be set above load current to prevent nuisance tripping. This decreases the sensitivity to LL faults. Because there are no zero sequence currents in LL faults, zero sequence ground fault protection will not work.

In this situation, negative sequence currents found in LL faults are useful. Because no negative sequence quantities exist in a balanced system, negative sequence pickups can be set below load current. The benefits are amplified when protecting a bus with multiple feeders.

**Downtime Fact:**

93 percent of businesses that experienced datacenter downtime for more than 10 days went bankrupt in less than a year.

Source: 2012 statistic from the National Archives and Records Administration, Washington
The Use of Negative Sequence Quantities in Protective Relaying

So why are negative sequence currents not regularly used in overcurrent protection? There are three main reasons:

1. When overcurrent protective devices were invented, symmetrical components were not understood on a widespread scale.
2. The technology to obtain negative sequence quantities with electromechanical relays was complex and expensive.
3. On systems with an ungrounded neutral, zero sequence quantities were optimal for detecting ground faults.

With the advent of microprocessor based relays, the second reason listed above is no longer true. Similarly, because protection engineers better understand symmetrical components and because most systems in the US solidly ground their neutral, the first and third reasons are no longer valid. Some drawbacks, such as lack of familiarity with the application and coordination, could still deter their use, however.

In addition to the application already discussed, negative sequence quantities are also used for:

- **Motor and Generator Protection** – Protects against rotor damage
- **Directional relaying** – Provides reliable polarizing quantities
- **Line Current Differential** – Adds sensitivity to high impedance LG faults and LL faults
- **Phase Selection** – Because negative sequence quantities are in phase with zero sequence quantities in LG faults (Figure A) this information can be used to determine the faulted phase of a LG fault

In summary, with the invention and application of microprocessor based relays, negative sequence quantities are another tool every protection engineer now has in his toolbox to design more secure and reliable systems.

Submitted by Doug F. Joens, PE – Electrical Engineer – dfjoens@powersystem.org

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Spectrum Acquisition for Communication Systems

PSE has a long history of helping our clients deploy communications systems for their utility applications. This communications support has intensified over the last five years as our clients focus on improved electrical grid analytics from locations across their territory. New utility communications are often wireless radio systems that require frequency spectrum to operate.

Historically, when utilities added a new or upgraded their mobile radio system they licensed Part 90 frequency spectrum from the Federal Communications Commission (FCC) in the traditional method of going through spectrum coordinators. However, as entities upgraded their voice system to trunked radio, which requires exclusive use frequency channels, traditional licensable spectrum has become scarce.

Additionally, as wireless advanced metering infrastructure (AMI) programs and feeder Distribution Automation (DA) have become cornerstones for many smart grid programs, the needs for spectrum have changed. AMI wireless backhaul communications have unique propagation and spectrum concerns due to near-broadband bandwidth needs to remote locations that are non-line-of-sight. DA is often challenged meeting coverage and reliability expectations. Unlicensed 900 MHz spectrum sometimes has challenges reaching these sites and data radios utilizing lower 150 MHz and 450 MHz narrowband frequencies tend to not provide sufficient bandwidth for AMI takeout concentration points.

These spectrum issues, and others, often require creative methods of acquiring licensed frequency to deploy wireless technologies in a modern utility environment. PSE has become very adept at analyzing our client’s needs and recommending the best spectrum solutions available in their area.

Some spectrum services we support:
- Running propagation studies in all spectrum bands to determine the best frequency for the application
- Engineering search analyses to find exclusive use spectrum to license
- Providing coordination engineering studies to the FCC or Canada (Industry Canada)
- Locating spectrum on the secondary spectrum market
- Negotiating with spectrum brokers to partition their license to sell or lease
- Facilitating the completion of the required FCC regulatory documentation

Specifically, PSE provided FCC Auction 87 support to assist several utilities acquire exclusive use paging spectrum that was re-purposed for mobile voice radio systems in preparation of the FCC narrowbanding mandate. A 34-site mobile voice system in the Midwest probably could not have been deployed without the acquisition of spectrum in this auction.

PSE has a proven track record on finding eloquent licensed wireless communications solutions for our utility clients. Contact us to discuss your critical wireless infrastructure design and spectrum needs.

Submitted by Charles Plummer – Director of Communications Infrastructure – plummerc@powersystem.org
What is the “cost” of electricity? What does it mean to “save” money on electricity? When evaluating the effectiveness of a demand reduction program, these are simple questions, but the answers are complex and vary depending on perspective.

From a customer perspective, the first measure of cost or savings is the amount due on their monthly utility bill. Residential customers can take this a step further by comparing the kilowatts used, cost per kilowatt-hour rate, and any fixed charges on their current bill to bills from previous periods. Commercial and industrial customers can also compare the amount due to previous periods, and often, provided the information is available on their bill, assess energy and peak demand charges. But for both customer classes, the electric bill includes generation, transmission, and distribution costs that sum to the total cost of electricity.

The cost of producing electricity tends to change as the load and the mix of generation resources utilized to meet the load change. Generally, the decision to operate a particular generator is based on whether or not it is the lowest cost generation to serve the load. If an electric utility is able to buy from the market at a lower price than the cost of generating its own power, it will generally purchase power from the market.

The wholesale energy market in the Midwest Independent Transmission System Operator, Inc. (MISO) was transformed to a centrally dispatched Regional Transmission Organization (RTO) market, or “Day 2” market, on April 1, 2005. This system of purchasing and selling energy allows electric utilities to make efficient use of their generation units and to buy power when their load exceeds their generating capabilities or when power can be purchased for less than their own cost of generation. In these markets, essentially all generation is sold to MISO, and all load is purchased from MISO. The energy price established by the RTO is not complete and does not include transmission, distribution, or the fixed costs of generation resources.

The generation component makes up approximately 45% of the typical electric bill. This includes an allocation for the fixed cost of each facility as well as the variable operating costs, particularly fuel and maintenance.

Fixed charges for distribution and transmission facilities necessary to serve customer energy needs are also allocated back to the ratepayers, with distribution costs comprising about 45 percent of the total bill and transmission costs comprising the remaining 10 percent. These transmission and distribution costs do not vary much from month to month, and are typically allocated to customers based on their peak demand during the billing period.

Programs must be evaluated in terms of their anticipated impact on each cost component, but utilities are faced with many layers of complexity. The ideal demand reduction program will provide cost savings for the generators, utilities, and residential and commercial customers, thus providing a “win” for all parties involved.

Submitted by Tom Butz, PE – Senior Planning Engineer – butzt@powersystem.org

What’s New at PSE

We continue to grow and are excited to add the following professionals to our engineering and technical staff.

- Johnathan Marquardt, Electrical Technician – Prinsburg, MN
- Kevin McCutcheon, Power Delivery Design Consultant – Marietta, OH
- Rick Seeling, Senior Consultant, Electric Distribution System Planning and Design – Minneapolis, MN
- Dave Wieben, Engineering Technician – Minneapolis, MN

PSE to Teach Upcoming EUCI Courses

February 25 - March 1 • Toronto, ON

PSE’s Chris Ivanov and Steve Fenrick will teach the following courses:

- Electric Load Forecasting: Introduction and Best Practices
- Demand Response: The Economic and Technology Considerations from Pilot to Deployment
- Benchmarking the Performance of Electric and Gas Distribution Utilities

Visit EUCI’s website www.euci.com for more information.
EMPOWER Critical Peak Pilot Year 2

Sioux Valley Energy (SVE) is an electric distribution cooperative serving approximately 21,000 customers in Minnesota and South Dakota. PSE assisted SVE with its EMPOWER Critical Peak Pricing (CPP) Pilot in 2011 and again in 2012. Based on the assessment of the 2011 pilot, various design aspects were revised and participation was expanded in 2012.

Participants and Test Groups
PSE helped establish the control group and two test groups defined as: 1) randomly selected with opt-out and 2) voluntary opt-in. A technology-only test group from 2011 was not continued for the 2012 pilot. Between the two remaining test groups, 413 customers participated in the 2012 CPP Pilot. Of particular interest was the number of voluntary participants which increased from 77 in 2011 to 213 in 2012. In fact, the voluntary opt-in test group participation exceeded the initial participation cap, which was then expanded to accommodate additional participants.

Participant Experience and Satisfaction
A key factor impacting the participant experience and satisfaction is the frequency of critical peak events. Driven by 2012 load and weather patterns, 24 critical peak events were called during June, July, and August. This was an increase of 13 or 118% over the number of events in 2011. In spite of this, the 2012 post-pilot survey indicated that 77% of the respondents would consider continuing in the pilot and 35% were highly likely to continue. While this was down from the 90% and 50% in 2011, the results remain strong. In 2012, an impressive 95% of respondents indicated they modified behavior at least partly to help SVE save money compared to 90% in 2011. Clearly, SVE is successfully communicating the purposes and goals of the program and has built a high level of trust that allows a partnership with its customers.

Demand Savings
PSE’s econometric assessment of the 2012 pilot demonstrates that participants in both test groups reduced usage during notified critical peak events. As in 2011, and as expected, the voluntary group was again the leading responder. See the graph for a comparison of the demand savings by test group and rate class.

PSE’s experience with multiple Dynamic Pricing Pilots indicates that customers will participate, engage, modify usage and benefit when programs are well designed and effectively communicated.

Cooperative Benchmarking Program Expands
PSE’s benchmarking program for cooperatives has helped managers answer the following questions:

1. What should our cooperative’s reliability indexes be, given our service territory conditions?
2. What would capital expenditures be for an “average” utility with our characteristics?
3. Are our operation and maintenance expenses in line with industry norms, after adjusting for regional wage levels, customer density, and vegetation challenges?
4. Is our distribution revenue requirement at an efficient level?
5. Is our productivity trend increasing, decreasing, or not changing?

In 2012 the cooperative benchmarking report expanded its results to include a benchmark analysis of right-of-way clearing expenses and customer satisfaction scores. As in previous years, we provided a customized, model-based expectation for each metric to participants. This expected value is compared to each cooperative’s actual values to help managers determine the historical performance in each area.

The blue bar in the table shows an example of the model’s expectation of a cooperative’s right-of-way clearing expenses. This is then compared to their actual expenses, shown in red. The benchmark value (blue bar) is estimated by examining the influence of variables such as members per line mile, level of vegetation in the territory, percentage of clearing that is outsourced, and cooperative size. This provides managers with a customized benchmark of what an “average” utility would be spending, given the particular challenges faced. Compared to simple costs per line mile or per customer, PSE’s analysis provides a much more accurate and fair method of benchmarking cost levels.

The customer satisfaction benchmark analysis was similar. It examined each cooperative’s electricity rate levels, recent outages, overall reliability levels, and the percentage of undergrounding, and then estimated an “expected” satisfaction score. This benchmark score was then compared to the utility’s actual score to estimate the each member’s “expected” residential member satisfaction (given its particular rates and reliability statistics). This provides a better performance measure than a simple customer satisfaction score.

Submitted by Rich Macke – Vice President, Economics, Rates and Business Planning – macker@powersystem.org, and Nick Nelson – Senior Rate and Financial Analyst – nelsonn@powersystem.org

Submitted by Steve Fenrick – Leader, Benchmarking and Economic Studies – fenricks@powersystem.org
The Utility Operations Dashboard Provides an Up-to-Date “Pulse” of the Utility

The utility dashboard provides a snapshot of the current state of the utility as it relates to outages, alarms, call center activity, and other key measurements. The user interface is readily customized based on automation systems in place and utility preferences, including user group specific views. In addition to improving communications between departments in the office, real-time system status can be viewed remotely on smart phones and tablets, including Apple iOS devices.

Example systems that may be integrated include:

- SCADA alarms above a user selectable importance level
- Real-time system, substation, and feeder level status and trends including feed and breaker position
- Outage and restoration information from the Outage Management System (OMS)
- Call volume, time on hold, dropped calls, etc. from Interactive Voice Response (IVR) and phone systems
- Real-time vehicle location and status from Automatic Vehicle Location (AVL) integration
- Map of outages, crew locations, etc. from the Geographic Information System (GIS)
- Communications network status via Simple Network Management Protocol (SNMP) interfaces to multi-vendor systems

The key benefit is an overview of all relevant systems. While some of this type of information is also available with the OMS, SCADA, GIS, and other systems, logging into those systems one at a time requires greater security and complexity. Yet with the dashboard, the user can still drill down to an individual alarm, outage, or locations such as substations with graphical representation of status and substation-specific alarms and outages.

Key Performance Indicators such as reliability statistics (e.g. SAIDI), system feed, work order load/average time open, and more can be captured and trended and viewed on demand.

If you would like to see the dashboard in action, please contact Kevin Zamzow to arrange a demonstration.

Submitted by Kevin Zamzow – Manager, Utility Automation and Communications – zamzowk@powersystem.org

Consolidates live utility operations data
Accessible to utility employees – anywhere, anytime
Customizable to your needs
Secure network
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Email shekelss@powersystem.org with questions, comments, or for more information.

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