Understanding Per-Unit Quantities

In power system analysis, it is common practice to use per-unit quantities for analyzing and communicating voltage, current, power, and impedance values. These per-unit quantities are normalized or scaled on a selected base, as shown in the equation below, allowing engineers to simplify power system calculations with multiple voltage transformations.

\[
\text{per unit quantity} = \frac{\text{actual quantity}}{\text{base quantity}}
\]

\[
\text{Percent quantity} = \text{per unit quantity} \times 100
\]

For example, a transmission system operating at 117,300 volts with a nominal base rating of 115,000 volts has a per-unit voltage quantity of 1.02 or 102% of nominal. Likewise, a distribution system operating at 12,100 volts with a nominal base rating of 12,470 volts has a per-unit voltage quantity of 0.97 or 97% of nominal.

\[
\frac{117,300 \text{ Volts}}{115,000 \text{ Volts}} = 1.02 \text{ PU} \quad \frac{12,100 \text{ Volts}}{12,470 \text{ Volts}} = 0.97 \text{ PU}
\]

While most engineers studying transmission systems will evaluate analysis results in a per-unit value as shown above, those studying distribution systems will typically convert the per-unit value to voltage value using a 120 volt base. So for the above example, the distribution system with an operating voltage of 0.97 per unit would be converted to 116.4 volts on a 120 volt base.

\[
\text{per unit quantity} \times \text{base quantity} = \text{actual quantity}
\]

\[
0.97 \times 120 \text{ Volts} = 116.4 \text{ Volts}
\]

Historically, per-unit values have made power calculations performed by hand much simpler. With many calculations now being done using computer software, this is no longer the primary advantage; however, some advantages still exist. For example, when analyzing voltage on a larger system scale with many different nominal voltages via step-up and step-down transformers, per-unit quantities provide an easy way to assess the condition of the entire system without verifying the specific nominal voltage of each subsystem. Another advantage is the fact that per-unit quantities tend to fall in a relatively narrow range, making it easy to identify incorrect data. In addition to these advantages, most power flow analysis software requires input and reports results per unit. For these reasons, it is important for engineers and technicians to understand the per-unit concept.

Continued on page 2
Understanding Per-Unit Quantities

In three-phase power systems, voltage and apparent power (VA) are typically chosen as bases; from these, current, impedance, and admittance bases can be determined using the following equations.

\[
I_{\text{base}} = \frac{\text{Apparent Power Base, } VA_{3\phi}}{\sqrt{3} \times \text{Voltage Base, } V_{LL}}
\]

\[
Z_{\text{base}} = \frac{\text{Voltage Base, } V_{LL}}{\sqrt{3} \times \text{Base current (A)}} \times \frac{(\text{Voltage Base, } V_{LL})^2}{\text{Apparent Power Base, } VA_{3\phi}}
\]

\[
Y_{\text{base}} = \frac{1}{Z_{\text{base}}}
\]

For equipment such as motors, generators, and transformers, the base power rating and voltage are typically used to calculate a per-unit impedance. In some instances it is necessary to convert these per-unit values with different power and voltage bases to one common base. The power base will remain constant throughout the system, and the voltage base is typically the nominal voltage for each part of the system. The equation for converting to a new impedance base is as follows:

\[
Z_{PU - NEW} = Z_{PU - OLD} \left( \frac{\text{base}V_{OLD}}{\text{base}V_{NEW}} \right)^2 \left( \frac{\text{base}VA_{NEW}}{\text{base}VA_{OLD}} \right)
\]

Assuming a 100 MVA apparent power base and the nominal base voltages shown in Figure 1 below, the following is a conversion of the impedances and the measured voltages to per-unit quantities.

**Per-Unit Impedance Calculations**

**GENERATOR**

\[
Z_{PU - NEW} = 0.12 \left( \frac{13.8 \text{ kV}}{14.4 \text{ kV}} \right)^2 \left( \frac{100 \text{ MVA}}{55 \text{ MVA}} \right) = 0.20
\]

**TRANSFORMER 1**

\[
Z_{PU - NEW} = 0.10 \left( \frac{115 \text{ kV}}{115 \text{ kV}} \right)^2 \left( \frac{100 \text{ MVA}}{55 \text{ MVA}} \right) = 0.20
\]

**TRANSFORMER 2**

\[
Z_{PU - NEW} = 0.08 \left( \frac{115 \text{ kV}}{115 \text{ kV}} \right)^2 \left( \frac{100 \text{ MVA}}{20 \text{ MVA}} \right) = 0.40
\]

**MOTOR**

\[
Z_{PU - NEW} = 0.15 \left( \frac{13.8 \text{ kV}}{14.4 \text{ kV}} \right)^2 \left( \frac{100 \text{ MVA}}{6 \text{ MVA}} \right) = 2.296
\]

**Per-Unit Voltage Calculations**

**BUS 1**

\[
V_{PU} = \frac{14.7 \text{ kV}}{14.4 \text{ kV}} = 1.02
\]

**BUS 2**

\[
V_{PU} = \frac{117.3 \text{ kV}}{115 \text{ kV}} = 1.02
\]

**BUS 3**

\[
V_{PU} = \frac{116.2 \text{ kV}}{115 \text{ kV}} = 1.01
\]

**BUS 4**

\[
V_{PU} = \frac{14.2 \text{ kV}}{14.4 \text{ kV}} = 0.99
\]

Figure 1: Example of conversion to per-unit quantities.

Submitted by Doug F. Joens, PE – Manager, Power Delivery Planning – dfjoens@powersystem.org
On Trend: Prepaid Metering

Similar to the wireless phone service carriers offering prepaid cell phone plans, electric utilities around the country are transitioning toward allowing their customers to pre-purchase electricity under the “pay-as-you-go” or prepaid metering programs—an alternative to the traditional post-pay concept. Statistics indicate that currently, around 200 electric utilities across 34 states in the nation are employing or piloting prepaid metering programs.

In the “pay-as-you-go” scenario, electric service remains connected as long as the balance on the account is positive. To help ensure continuity of service, customers receive daily alerts via text, email, web portal, or phone message with account balance and usage information. Payment options for prepaid accounts include payment by phone, on the web (if using debit/credit card), or in person at designated payment locations. However, under the prepaid service arrangements, customers are not limited to a payment due date but have the convenience of initiating payments on their own schedule, allowing for smaller, more frequent payments.

Prepaid metering programs help customers break the vicious cycle of ever-increasing balances caused by late charges and other collection fees, while enabling the utility to reduce past due accounts. Under prepaid metering, utilities waive the traditional deposit. Due to remote connect/disconnect capabilities of the Automated Metering Infrastructure (AMI) system, the disconnection/reconnection service charges are lowered substantially or eliminated. There are also no late fees under the programs. Furthermore, the prepaid metering programs can be structured so that a customer may “roll over” an existing past-due balance. Then, each time a payment is made, a certain percentage of that payment is applied toward the old balance.

Energy efficiency is another positive outcome being observed with prepaid metering programs; i.e., as customers become more aware of their daily energy usage, they are better equipped to change their behavior accordingly. As a result, a conservation effect around 10-12% per participant often accompanies the prepaid metering program roll-out.

To assess and justify a planned residential prepaid metering program to its directors or a regulatory agency, a utility should conduct a benefit-cost analysis (BCA) which includes the following: Ratepayer Impact Measure (RIM), Total Resource Cost (TRC), Program Administrator Cost (PAC), and Participant tests. These tests examine the benefits and costs and provide summary information from the various perspectives of the program participant, the non-participating ratepayers, the utility, and society as a whole.

Submitted by Elena Kanaeva-Larson – Rate and Financial Analyst – larsonel@powersystem.org

New Technology and Organizational Change: The Product Management Approach

We are seeing a growing list of new products and services piloted and deployed at medium and larger-sized utilities. These include prepaid metering, direct load control for residential, new time-of-use (TOU) pricing programs for both residential and commercial, smart thermostat for residential, new web hosting content, electric vehicle charging devices and installation, deployment of commercial energy management systems with the new OpenADR protocol, lighting services, and others.

Utilities often try to manage a combination of these new products and services using their existing departmental structures. While the existing structures have fairly clear lines of demarcation, this can often lead to complications and confusion regarding ownership and prioritization between competing initiatives. Introducing new products and services requires well-coordinated efforts between several departments, including:

1. Business process review and changes
2. Appropriate training with the new products/services
3. Field or premise installation and maintenance processes
4. Coordinated marketing and advertising
5. Buy-in from management and all affected departments, including IT, which often has a major role with new product/services

Similar issues occurred within the telephone industry post-1990, when many new products were introduced (caller ID, voicemail, long distance services, cellular, and eventually Internet access for the home or business). Prior to that, telcos had a single product. The resultant output of so many new services was the adoption of a new product management structure to oversee the introduction and the day-to-day management of their new products/services. The product management group coordinated various departments throughout every step of the process including maintaining primary responsibility for managing sales, revenues, and costs.

There are definite benefits for electric utilities to adopt similar organizational changes by employing a product management structure to best manage the diverse disciplines of the introduction, deployment, and maintenance of new products and services. PSE recommends considering this approach in your next strategic technology plan initiative.

Submitted by Rick Schmidt – Vice President, Utility Automation and Communications – schmidt@powersystem.org
ASK PSE A QUESTION
Are There Affordable GIS Options Available to Smaller Utilities?

Recent Cost Reductions Open GIS Opportunities Even for Small Utilities.

Implementing a Geographic Information System (GIS) as a spatial analysis tool has now become increasingly viable for small utilities due to subscription-based software licensing options, the steady decline in hardware prices, and a sharp rise in integration ease between AMI, AVL, OMS, SCADA, Engineering Modeling, and Customer Information systems. This drop in cost, coupled with increasingly robust analytics and connectivity, creates a very compelling case for a GIS solution right at the center of a utility’s core.

In recent years, the GIS industry’s leading software vendor, Esri®, made user-aligned changes to its Enterprise License Agreement (ELA) programs. The subscription-based ELA programs allow for flexible access to full suites of Esri’s software solutions at far less cost than purchasing each piece of software individually. While every utility services a unique demographic, tiered ELA plans based on the number of users and variable licensing options can tailor the package to fit a range of utilities and keep upfront costs at a minimum.

However, Esri isn’t the only option for a utility to leverage GIS. The open-source GIS realm is growing exponentially with new offerings coming to market regularly. Analytical tools built on open solutions such as QGIS for geographic editing, mapping, and web map deployment, or PostGIS running on top of PostgreSQL to manage geographic and tabular data have really widened the implementation options and brought startup costs even lower.

As with most things technology related, the continuing trend of peer-to-peer and business-to-business collaboration provides a consistent push toward improved business intelligence and tools for utilities. Through process automation and enterprise application interoperability specifications like MultiSpeak®, tapping into huge volumes of information for detailed analytics has never been easier. Think of the GIS as the tool that can greatly enhance your other automated systems, resulting in improved business processes. It has become clear that GIS alone is far beyond an electronic map. Automated cross-communication between the once disparate grid components is leading to better informed solutions and higher productivity.

With the level of ESRI GIS maturity and growth, a small utility does not require in-house expertise to set up and maintain its new GIS program. Consulting firms such as PSE can help utilities set up GIS while also training their employees in best practices for maintaining the system as a long-term solution.

Submitted by Logan Suhr – GIS Analyst – suhrl@powersystem.org

Electric Rate Training – In House

The rate setting process is important and fundamental to the electric utility industry. It often involves personnel from multiple disciplines to assemble the necessary financial and operating data, evaluate the impact of new rate alternatives, and decide on the best option for the utility. The utility’s management and governing boards must approve a new rate design or changes to the present rates. Clearly, setting rates is an expansive process, and utilities rightly devote substantial time and resources to planning, developing, and administering their rates, as well as communicating the rationale for rate levels and their bill impacts to customers.

Having an understanding of rates is beneficial to most, if not all, utility employees. However, providing this type of training on a broad scale to managers and inside and outside employees can be very difficult. We have developed two fully customizable in-house rate training options to fill this need. Electric Rate Essentials is a 3-hour training session designed to provide all of your employees and directors a high-level and essential understanding of rates and how they intersect with various business functions. Electric Rate Training for Decision Makers is a more in-depth 8-hour seminar designed for management and key staff who participate directly in the rate-setting process. Sessions can be held in one day or spread over two days and can be combined and tailored to meet your target audience. Topics include:

- General industry and rate setting fundamentals
- The utility’s role in providing electric service
- Measurements of electric consumption
- A review of your rates with example bill calculations and Q&A
- How to determine how much revenue the utility needs to collect
- The general concepts and purpose of a class cost-of-service study
- Rate design objectives
- Current industry developments and their impact on electric rates

Staff and decision-makers will leave with a better understanding of rates and the rate-making process both for their utility and within the industry. This will foster valuable internal and external education and ongoing discussion that will help the utility anticipate and respond to industry challenges while also building trust and confidence in the rate setting process.

Submitted by Jeff Laslie – Senior Financial Analyst – lasliej@powersystem.org
Navigating the Bulk Power System and NERC Compliance

Understanding Bulk Electric System

The North American Reliability Corporation (NERC) defines the Bulk Power System (BPS) as “facilities and control systems” necessary for operating electrical transmission systems as well as the generation systems needed for supporting the transmission systems. NERC ensures that the BPS operates reliably through the development and enforcement of NERC Reliability Standards. Understanding the basic definition of the BPS is key to establishing a utility’s bulk electric equipment system list and programs for compliance with the NERC Reliability Standards.

The Bulk Electric System (BES) represents the elements which comprise the BPS. The basic definitions of the BES include:

1. Transmission elements operated at 100kV or higher
2. Real and reactive power sources connected at 100kV or higher
3. Does not include facilities used for local distribution

These core definitions establish a baseline for determining which facilities make up the BES. NERC’s website further clarifies what are considered BES facilities with a list of five inclusions and four exclusions of transmission and generation elements. NERC’s website also has a BES Definition Implementation Guidance document designed to assist in categorizing and formalizing a BES equipment list.

Once the BES equipment list is formally established, planners, owners, and operators of the BPS are required to develop and implement programs to ensure that BES elements comply with the NERC Reliability Standards, which encompass 13 areas of transmission planning and operations, such as Critical Infrastructure Protection (CIP) and Protection and Control (PRC). Each of the 13 areas has numerous standards which must be interpreted and developed into specific programs. For example, PRC-005-5, Protection System, Automatic Reclosing, and Sudden Pressure Relay Maintenance is a reliability standard to be used in developing a program to ensure these systems operate appropriately and are tested over time.

Complying with the NERC Reliability Standards translates into implementation by having the following program components in place:

1. Reasoning or justification for program points and assumptions
2. Defined program points and activities
3. Implementation of process/tools for executing the program and documenting results
4. Demonstration of control of the process by monitoring, detecting, and correcting for elements not meeting program implementation and or results expectations
5. Documented results of the program including historical context

Understanding the definitions of BPS and BES is the starting point for identifying BES equipment, the appropriate NERC Reliability Standards, their application to the BES elements, and having a complete asset management program that will manage risk and ensure compliance with auditable results.

Submitted by Charles Blecke, PE – Senior Utility Consultant – bleckec@powersystem.org

Documents used for reference:
NERC Glossary of Terms Used in Reliability Standards:

NERC BES Definition Implementation Guidance, August 2014:

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PSE is driven to be your trusted advisor for all of your consulting and engineering needs. Our services include:

- Communications, IT, and Smart Grid Automation
- Economics, Rates, and Business Planning
- Electrical Engineering
- Planning and Design
- Procurement, Contracts, and Deployment

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