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SCOPING STUDY OF INTELLIGENT GRID PROTECTION SYSTEMS

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PREFACE

The California Energy Commission Energy Research and Development Division supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

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ABSTRACT

Widespread blackouts cause major disruptions to electricity consumers and to the economy. Protective relays have played a major role in either contributing to the cause of the blackout or failing to mitigate the speed of the blackout in virtually all of the major blackouts dating back to the first major New York blackout in 1965. This report analyzed the state-of-the-art of synchrophasor/phase angle measuring unit technology in the United States, the transmission constraints of imported power into California and the state-of-the-art of remedial action and special protection schemes in California. The authors recommended appropriate projects to apply synchrophasor technology for a new or improved special protection scheme in California to help prevent blackouts and increase the reliability of the electricity grid.

Keywords: Relays, synchrophasor, phase angle, blackouts

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EXECUTIVE SUMMARY

Introduction

Protective relays have played a major role in either contributing to the cause of the blackout or failing to mitigate the speed of the blackout in virtually all of the major blackouts dating back to the first major New York blackout in 1965. Zone 3 impedance relays played a major role in the July 2, 1996 blackout on the West Coast, the August 14, 2003 blackout on the East Coast and in the original 1965 New York blackout. In all three blackouts the zone 3 impedance relays which were intended only as backup to the primary protective relays operated incorrectly under heavy load conditions. Unusual circumstances in terms of weather and the configuration of the high voltage transmission grid that was not anticipated or studied by protection and operation engineers also contributed to these blackouts.

Two significant trends have taken place over the last 15-20 years that have had an impact on the vulnerability of the high voltage transmission grid to withstand major blackouts. Utilities have been operating the high voltage transmission grid closer to the margin throughout the United States and the world, resulting in a smaller difference between reliable and unreliable operation. By and large they have been pressured into doing this because of the rapid growth in large metropolitan areas, the lack of investment in the transmission infrastructure and the reluctance of the general public to allow transmission lines to be built near their neighborhoods. Another trend has been the installation of remedial action schemes (RAS) and special protection schemes (SPS) to protect against multiple contingencies. These schemes provide a safety net to protect against extreme conditions but they are prescriptive by nature. The protection and operation engineers must anticipate these conditions and set the special protection schemes accordingly. This often means taking precipitous action and leaving transmission capability on the table under less stressed operating conditions.

The installation of global positioning satellite (GPS) technology by the military in the mid- to late-1980s along with the rapid development of microprocessor technology has allowed for more intelligent protective relays and special protection schemes. This smarter technology can accurately measure the phase angle ("phasor") and voltage and can apply a GPS time stamp to the flow of power between two substations. The actual stress on the system can be measured very accurately by applying this phasor technology over a wide geographic area. This allows for more adaptive and flexible protective relay schemes and SPSs and could lead to a transmission grid operated more reliably and economically.

The western United States has led the effort in installing and applying phase angle measuring unit (pmu) technology for the last 10 years. The effort in the West is called the Wide Area Measurement System (WAMS) and is governed by the Western Electricity Coordinating Council (WECC). The Eastern Interconnection started a "phasor" initiative after the August 14, 2003 blackout called the Eastern Interconnection Phasor Project (EIPP). Recently the two initiatives were merged under one umbrella organization called the North American Synchrophasor Initiative Project (NASPI). The Bonneville Power Administration (BPA), Pacific Northwest Laboratories (PNL), Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) have led the effort in installing pmu capability at their facilities. There are a sufficient

number of pmus installed on the California – Oregon Intertie from Washington to California to provide wide area visibility, meaning that the actual real time state of the power system is known and application projects could be utilized. There is a lack of visibility in the Rocky Mountain area because insufficient pmus have been installed.

Project Purpose

The purpose of this project was to perform a scoping study to analyze transmission system protection issues, identify state-of-the-art technical protection solutions and their value for an intelligent system and develop stakeholder-supported recommendations for a technology program.

The specific project objectives were to:

- Evaluate system protection issues, needs and opportunities in consultation with the organizations participating in the TRP Policy Advisory Committee (PAC).
- Review state-of-the-art intelligent system protection technologies for addressing these issues, needs and opportunities with manufacturers and suppliers of promising system protection technologies.
- Review ongoing system protection research and development (R&D), field test validation projects and industry standards activities and explore opportunities to collaborate on research, development and demonstration (RD&D) that is synergistic with California's system protection issues, needs and opportunities.
- Develop prioritized recommendations for intelligent system protection R&D, field test validation and other related technology transfer activities that offer the potential to yield significant reliability, increased transfer capacity and other benefits for California's electricity consumers.
- Review and obtain feedback on this recommended system protection R&D agenda from the TRP PAC, Technical Advisory Committees, equipment manufacturers and other industry experts.

Project Results

The western United States has been installing pmus since the early- to mid-1990s. BPA accepted the responsibility of being the repository for most if not all of the pmu data at their Ditmer control center in Vancouver, Washington. They had two phasor data concentrators (PDCs) at their site that accepted the pmu data on a real time basis. The data was primarily used for disturbance analysis, generation modeling and data modeling. The BPA reliability coordinator at the Ditmer control center monitored the data and gained experience with it but they had no operator action available to them because no engineering studies had been conducted to correlate the angular relationship and the level of stress on the system.

PNL was in the forefront of research to provide real time displays and operator screens to enhance situational awareness for operators. They conducted advanced research into simulating

actual real time operating scenarios at control centers to include the trending of data and a real time display monitor (RTDM).

The Institute of Electrical and Electronic Engineers (IEEE) established the first synchrophasor standard in 1995, which was named 1344-1995. The standard was updated in 2005 and renamed C37.118-2005. The present standard defined measurement convention and measurement quality and communication protocols and all pmus must meet these requirements to be compliant. Communication latency, performance under dynamic conditions, aliasing and instrument transformer errors were areas that need to be better defined and further researched.

There are over 14 pmu manufacturers that could be grouped into two categories: 1) manufacturers whose primary product line was disturbance recorders and monitoring equipment; and 2) manufacturers whose primary product line was protective relays. Schweitzer Engineering Labs (SEL) and GE were two mainstream relay manufacturers with somewhat different philosophies. SEL provided pmu and relay functionality in one hardware package while GE provided a standalone pmu package. Both manufacturers made quality equipment, but some protection engineers expressed concern about the reliability of the overall pmu and protective relay in one package.

Almost all protection and control schemes on the grid were local in nature. This means that the sensing and tripping took place in one substation, typically with some schemes utilizing telecommunications between adjacent substations to coordinate the protection. The primary interest in applying synchrophasors was from a wide area standpoint because the intelligence to detect a stressed system that is close to collapse could only be determined from a wide area. Some potential applications that hold promise were wide area voltage control, small signal stability control and transient/dynamic stability control.

SPSs were the primary means of wide area control, although some were used for local problems as well. SPS schemes were prescriptive in that typically load flow and transient stability studies must assume worst case conditions to ensure that there was adequate protection during these times.

A step forward in applying SPSs will be to develop methods to control transient stability that are less dependent on off-line studies and that use more on-line computation. What was proposed was developing soft-computing techniques using pattern recognition, neural-networks and expert systems to decide upon the best control action. This type of approach for SPSs was unprecedented and would be considered a proactive type of scheme in that action could be taken ahead of time to prevent outages from occurring in the first place.

Pmu/synchrophasor technology has been available for the last 15 years and has been used primarily as a system monitoring and analysis tool. This technology provided invaluable insight into finding the root causes for major system disturbances, including the August 10, 1996 and August 14, 2003 disturbances. There was a growing trend across the United States of systems being operated much closer to the margin, where voltage collapse and transient stability could occur.

California relied heavily on imported power from both the Northwest and Southwest and many SPSs determine how much power can be imported based on voltage and transient stability limits. More intelligent special protection schemes that would take action based on actual real time conditions would allow power to be imported nearer the maximum limit.

No organizations have employed any kind of pmu-based application. The North American Electric Reliability Corporation (NERC) was very supportive and encouraged the use of pmus in a real time application, and the authors believed that sooner or later it will happen. The authors also believed it was very important to apply pmus in a real time application as quickly as possible to become confident with the technology and to wring out any of the concerns such as telecommunication latency and dynamic response.

Both PG&E and SCE had extensive special protection/RAS scheme applications that impacted both power imported into California as well as internal generation in California. PG&E had SPSs that impacted the California – Oregon Intertie, load and generation in San Francisco and Diablo Canyon generation. SCE had SPSs for power imported into Southern California and for generation at its Big Creek hydroelectric power plant. All of these SPSs protected against multiple contingencies. PG&E and SCE installed a significant number of pmus on their bulk transmission system and had extensive high speed telecommunication infrastructure. PG&E and SCE would be good candidates for a demonstration project. The authors concluded that SCE had a slight advantage in terms of their software and expertise in pmu technology.

The project team recommended that PIER sponsor a synchrophasor demonstration project at SCE's Big Creek project to include the installation of a PDC, a centralized programmable logic controller (plc) and the software to program the plc as a special protection scheme.

Project Benefits

California will benefit in the short term by increased reliability of generation at Big Creek. More costly generation could be backed down assuming Big Creek could be operated at higher levels of generation, saving Californians the incremental cost between Big Creek generation and more costly generation.

In the long term the knowledge gained from the demonstration project could be transferred to more complicated SPSs such as the California – Oregon RAS scheme. The potential for savings was very large, assuming that more power could be imported into California at least part of the time. The cost saving would be the incremental cost between primarily thermal generation in California and very economic hydroelectric power in the Pacific Northwest.

CHAPTER 1: Introduction

System Protection state-of-the-art technology utilizes discreet microprocessor (digital) relays that can be programmed individually or to work in tandem to protect transmission lines, transformer banks and generation. Some of the more advanced digital protective relays incorporate GPS receivers, digital fault recorder capability, and phase angle measurement (PMU) technology engineered into one relay. EHV transmission lines have redundant primary protective relays that utilize high-speed telecommunications at each end of the line to operate in tandem as high speed differential protection (directional/phase comparison, pilot wire and permissive over-reaching transfer trip). Additionally there are backup relays on each transmission line that serve as local relay failure and remote breaker failure protection. All of these relays are set based on a prescribed set of conditions assuming relatively normal system configuration. During abnormal system conditions, however, where voltages, phase angles, frequency and/or fault currents vary significantly from preset conditions, the protective relays can sometimes miss-operate, either operating when they shouldn't (no fault, load encroachment or stable swing condition) or not opening when they should (fault conditions or unstable swing condition).

In virtually all of the major blackouts in the last thirty years, protective relays have played a major role in causing the blackout, exacerbating the blackout or failing to mitigate the spread of the blackout. For example, in the August 14, 2003 blackout on the East Coast and the July 2 and August 10 1996 blackouts in the West, zone 3 impedance relays played a major contributing role as well as many transmission and generation protective relays. In each of these blackouts, due to an unusual and unanticipated set of circumstances, the EHV transmission grid became configured in highly abnormal operational states that were not anticipated or studied by protection and system operating engineers.

One other observed trend that has been taking place at an accelerated rate over the last ten years is the installation of Remedial Action Schemes (RAS) or Special Protection Schemes (SPS). There are SPS installed in the WECC that act as a first line of defense and as a safety net to mitigate the impact of cascading outages in WECC. The most important is the California – Oregon Intertie (COI) RAS/SPS, which responds to the initiation of multiple 500 kV transmission faults in California and Oregon by tripping generation in the Northwest, inserting both series and shunt capacitors in California and Oregon and ultimately separating the WECC into two major controlled islands under worst case scenarios as the ultimate safety net. The complexity caused by proliferation of these schemes, particularly in the Western interconnection (WECC), could have unintended consequences, potentially causing major problems and becoming a major trap for transmission operators and ISOs.

There are, however, new, potentially more intelligent, system protection technologies, utilizing phase angle ("phasor") measurement and other features, which offer the potential to create a more "ductile" and adaptive grid system. These new protection technologies can more effectively isolate faults, help generators to sustain their in-step operation, and otherwise

adaptively respond to avoid blackouts and other fractured grid operating conditions. For example, although the COI RAS/SPS has operated successfully many times to prevent or arrest cascading outages, there is the potential to use adaptive system protection technologies to allow the COI to operate more reliably and with greater post-disturbance transfer capacity, by adapting the operation of relays and other system protection equipment to varying system conditions based on information from wide-area phasor measurement technology.

1.1 Project Approach

1.2 Interviews

Several meetings were held with BPA, PNNL, SEL, CAISO, PG&E and SCE to discuss their applications utilizing synchrophasors and to ask them what their concerns were and vision for the future. A similar list of questions was developed for all companies but some questions were tailored to fit the company personnel being interviewed. The companies were picked because of their leadership and involvement in synchrophasors and importance to the California market and WECC grid.

1.3 Meetings

The authors attended several industry meetings and seminars to learn and interact with industry experts regarding the state of the art of special protection schemes and synchrophasor applications. Among the meetings and seminars attended were: Western Protective Relay Conference in Spokane; Several IEEE PSRC (System Protection Relay Committee); two protection seminars at PG&E; and one synchrophasor application seminar at SCE. The authors has several phone calls and follow-up meetings with SCE regarding their Big Creek special protection schems.

1.4 Papers

The authors downloaded several papers from the IEEE digital library to review what the stated of synchrophasor technology was around the world. Some of those papers are listed in the reference section of this report.

CHAPTER 2:
Project Outcome

2.1 Task 1 Report

2.1.1 Background

There are two major "wide area monitoring (measurement) system" projects across the United States: 1) WAMS – Wide Area Measurement System in the WECC has been developed and in use over the last 10 years; 2) EIPP – Eastern Interconnection Phasor Project that was initiated primarily as a result of the August 14, 2003 blackout.

This research project of course is focused on the benefits of R&D for California Utility customers and, since California is one of 14 states that comprise the WECC, all of our attention is on WAMS.

After the July 2 and August 10, 1996 disturbances in the WECC there has been a growing concern about impacts of wide area disturbances and a significantly increased need to implement a broader "Wide Area Measurement (Monitoring) System". Today, WAMS has over 60 phase angle measuring units (PMU) installed at various high voltage substations located throughout the Western grid. These PMU devices utilize synchrophasor technology to measure the voltage magnitude and phase angle of a voltage waveform that is referenced in time by a GPS signal. Since everything is referenced to a common GPS signal that is very accurate, one can then monitor very accurately the phase angle between substation locations regardless of how far apart they are. By knowing the phase angle and voltage magnitude, one can calculate the real power (MW) and reactive power (Mvar) between two substations assuming the impedance data (model data) is known. This is huge because if both phase angle and voltage magnitude are known and continuously updated, one can measure the electrical stress on the system and make accurate predictions on how stable the power grid will be. Absolute phase angle between two major substations does give some measure of how much power is flowing but even more important is the rate of change of the phase angle between the two substations. By trending the phase angle difference one can start building a knowledge base of the stress on the system. Also because synchrophasors can monitor phase angles a minimum of 30 times per second, one can determine the dynamic stress on the system. It is possible to measure the frequency of oscillation on the system in addition to determining how well damped the oscillation frequency is. This is another important tool that system operators never had available to them before.

2.1.2 Key Findings

In our discussions with BPA, PNNL, Schweitzer Engineering Labs, SCE, PG&E, CAISO and Virginia Tech we asked a number of questions and learned where the industry is at the present time.

Following are the key findings:

BPA has installed 24 PMUs and receives data from a total of 36 PMUs into 2 data concentrators.

- BPA has assumed the responsibility of the super data concentrator site where a majority of PMU data is sent to their data concentrators and archived.
- This data is primarily used for: a) Disturbance analysis; b) Generation modeling; and c) Data monitoring.
- Data is presented in three forms to BPA dispatchers and Pacific Northwest reliability coordinators; a) streaming data reader – real time information in graphical form that is continuously updated; b) "clock display" – phase angles at various locations are shown in real time; c) RTDM – real time display monitor.
- This dispatchers and reliability coordinators are monitoring the data and getting experience with it but no operator actions are taken as a result of the monitoring of the data.
- Most of the Pacific Northwest, California and the Arizona/New Mexico areas have fairly good PMU coverage. The Utah, Idaho and Alberta areas have very poor coverage by PMUs.
- BPA's dispatchers are comparing the results of the state estimator and PMU data and finding very close correlation.
- BPA is interested in finding additional applications and the WACS (Wide Area Control System) project is a possible application that could be used in the future. During the June 14, 2004 Westwing disturbance, WACS would have taken the same control actions as the COI RAS did although it was in monitor mode only. It's not clear where WACS is going in the future as Carson Taylor has retired from BPA and someone new will have to pick-up where he left off.
- Areva is involved in using PMU data in the WECC Western Wide System monitoring project for state estimation.
- BPA indicated they don't calibrate the PMUs. They're very accurate and don't appear to drift very much. Potential transformer and current transformers are another story. Typically potential transformers are 1 percent accurate and CCVTs particularly at the higher voltages are not very accurate and can drift. Current transformers are probably a little more accurate and tend not to drift as much. It's still not clear how accurate the PMUs need to be because there are no specific applications yet. If they are used for state estimation, accuracy within 1 to 2 percent may be OK, but if they are used for system protection and special protection schemes, they may need to be more accurate. In any event, the accuracy of the instrument transformers is part of the equation.
- IEEE Std. C37.118-2005 is the present standard regarding synchrophasors.
- There are no specific alarms provided by the PMU data because there are not yet guidelines on the relative phase angles at various locations versus stressed operating conditions where nomogram limits may be of concern.
- BPA is doing short term trending on flows and voltage particularly to validate model data with actual data during disturbances. The data can be archived for a year or more,

however there is no long term analysis in terms of pattern recognition of relative phase angles during different seasons and operating scenarios.

- There was concern expressed about the reliability and security of the telecommunication system particularly regarding control schemes, system protection or special protection schemes. It is one thing to use PMU data for state estimation purposes where if some data drops out for a couple of 2 second scans it is not a problem. If on the other hand there is even a momentary failure of the telecommunication system for a special protection scheme, it could mean the failure of the special protection to either take the appropriate action or to take it too late. That means that very reliable and redundant microwave and/or fiber optic telecommunications must be used.
- There is some planned R&D in the area of data concentrators which take inputs from multiple PMUs. Data concentrators coordinate the amount of PMU data input into them but do add some additional time delay into the process.
- Southern California Edison and LADWP are doing some research and demonstration projects for PMUs and special protection schemes. Bharat Bhargava from SCE has been heading up this effort.
- Also EPRI has been involved in R&D regarding WAMS and WACS. Stephen Lee from EPRI has been the project manager in this area.
- The long term vision is to continue installing PMUs and data concentrators to obtain better visibility of the WECC system but what everyone is looking is to install an application that utilizes synchrophasor technology to take control action to keep the system in a stable and secure state.
- PNL is looking for applications of PMU technology to improve sequence of events, operator situational awareness, and L&P state estimation.
- PNL has heard from several protection engineers throughout the country about the reliability of including synchrophasor measurement and protective relaying in one box.
- PNL is concerned about telecommunication network issues and the role it plays in reliable commercial applications.
- PNL is concerned about the sparse PMU data available so far.
- PNL has also been actively involved in the WACS project that Carson Taylor and Dennis Erickson worked on from BPA. John Hauer and Steve Widergarten have been working on a project to make the grid more rigid (robust) and less immune to undamped oscillations.
- PNL has been collaborating with TVA on a super PDC data concentrator to improve the application of PMU data
- SEL (Schweitzer Engineering Labs) are using synchrophasors imbedded in their relays. The SEL 421 relay has a full synchrophasor (GPS time stamped phase angle and voltage) built into the relay. The SEL 451 relays also have synchrophasor capability. There are 1199 SEL 421/451 relays installed on the Western interconnection and 2664 SEL 421/451 relays installed on the Eastern interconnection.

- The SEL 321 and 351 relays can be retrofitted with firmware to enable synchrophasors. As an indication of the number of potential synchrophasors that could be utilized, there are over 10,000 SEL 321/351 relays installed in ERCOT alone.
- SEL does extensive simulation testing in their laboratories and the PMUs meet or exceed the existing IEEE standards. Other than using the same instrument PTs and CTs, the synchrophasors are isolated from the protective relay functions. The same concern was expressed years ago regarding fault location in the same package as protective relays and has proven not to be a concern.
- SEL is involved in a data concentrator project with SDG&E and with Tasmania in a line impedance measuring project.
- SEL is very supportive of PMU data being able to provide accurate data for state estimation and model validation. They demonstrated that on an ideal 14 bus model, 2 PMU locations would be sufficient data for a state estimator to converge. In fact with 30 percent of available data from PMUs, there the standard deviation would be 0 percent and with 10 percent available data from PMUs, there would be .1 percent deviation.
- SEL relays are calibrated from the factory to meet existing standards which is within 1 electrical degree. The GPS receivers are generally accurate within 100 nanoseconds but they are specifying 500 nanoseconds to be on the conservative side. The basic recommendation would be to test the PMU at the same interval that the relay is tested. They meet IEEE C37.118 standard.
- CAISO uses RTDM displays that feature synchrophasor data as a further tool for their reliability coordinators
- CAISO effectively diagnosed system oscillations on the Pacific DC Intertie in early February 2008 by using graphical tools developed for RTDM.
- SCE has installed 16 PMUs that are connected to one PDC.
- SCE has written some very powerful and useful software to analyze synchrophasor data. From archived PMU data, they can analyze modes of oscillation, frequency damping and phase angles.
- SCE has used their analysis software to analyze archived data from the August 4, 2000, June 6, 2002 and June 14, 2004 disturbances.
- Their PDC can handle up to 30 PMUs.
- SCE identified the Big Creek project as a potential candidate for synchrophasor wide area demonstration project.
- PG&E has installed 7 PMUs with immediate plans to install 4 more PMUs. This should give them excellent coverage of their 500 kV system in addition to Diablo Canyon and Helms power plants.
- They are upgrading their Areva state estimator to include PMU measurements.
- PG&E will be upgrading their COI RAS scheme and communication network in 2008.

- PG&E has a couple candidates for a wide area demonstration project: A) Diablo Canyon double line outage SPS; and B) Metcalf SPS.

2.1.3 WECC Transmission Paths and Major RAS/SPS

The WECC has over 70 transmission paths that have planning and operating ratings. These transmission paths consist of multiple transmission lines in a transmission corridor that connect one geographic region to another one. Stability and load flow studies are done under various conditions and seasons to ensure that the transmission path can be operated up to its maximum rating reliably and securely.

Many of the transmission paths in WECC are not constrained and therefore do not have operational transfer capability (OTC) ratings applied to them. The major paths such as the California – Oregon Intertie (COI – Path 66), Path 15 and Path 26 and East of River (EOR) have a significant impact on the reliability of the WECC grid and all have complicated operating procedures and operating nomograms that monitor simultaneous conditions to ensure a safe and reliable operating point. The following paths have operational transfer capability ratings that have significant impact imports into California:

Many of the above mentioned paths have Special Protection/Remedial Action Schemes that are associated with them. Without these special protection schemes, all of these major paths would be de-rated by a substantial margin. Under worst case scenarios thousands of MW of generation and load are dropped to prevent instability and voltage collapse under multiple contingency conditions.

There are many other RAS/SPS in California that impact internal transmission paths and local generation. These special protection schemes either trip generation or run back generation and/or trip load to assure reliable operation under unexpected multiple contingencies.

All of these special protection schemes are event driven (based on line/transformer/generator outages) which then take prescriptive actions based upon a pre-defined set of base case conditions. These schemes are conservative because they are based on the most stressed system conditions. Under most operating conditions, capacity is left on the table (unused) because of the conservative assumptions and strategy. Having said that, there is no other good option to do otherwise based on technology that was available at the time. Even though many of these schemes use "fault tolerant" logic (two out of three voting scheme), they still are reactive in that they must wait for a line, transformer or generator to relay and they base their output actions on analog values flowing across the transmission paths or individual transmission lines.

2.1.4 Scope of R&D Project

The scope of this project is to identify those applications where an adaptive special protection scheme can be used to take control actions that will maintain system stability without sacrificing equipment or tripping too much load or generation. There are other control actions that could be taken such as running back generation, controlling SVCs and inserting series/shunt capacitors that are as effective, and less draconian than dropping large amounts of load and generation.

Synchrophasors are the perfect vehicle for accomplishing this because they are monitoring the two quantities (phase angle and voltage) that have the biggest impact on the transmission grid. And they can take control actions before there is an event and so are more proactive and precise than existing special protection schemes. Regardless of system conditions and events based conditions including both scheduled and forced outages, the synchrophasors are monitoring the precise health of the transmission grid in real time and in fractions of a second.

There are still a number of issues that need to be addressed and ironed out before this technology can be put into service. The following are some of the issues that an R&D project can sort out;

- Reliability of telecommunications network.
- Latency of telecommunication equipment.
- Accuracy of PMUs.
- Performance of PMUs under fault and stressed conditions.
- Accuracy needed for CCVTs and CTs.
- Identifying when to take action (based on stability studies?).
- Identifying what action to take and how much.
- Maintenance intervals of PMUs and associated equipment

These are some of the issues that need to be addressed but the upside to synchrophasor technology is huge while the risks can be identified and managed.

2.1.5 August 14, 2003 Disturbance Recommendation

One of the key August 14, 2003 recommendations was to *Evaluate and Implement "Defense in Depth" System Monitoring, Control, and Protection Measures to Slow Down and Mitigatethe Severity of Cascades*

The following key observation came out of the August 14, 2003 recommendation: "*An overall defense in depth philosophy and integrated strategy is needed to protect today's bulk power system from cascading blackouts. Such a system would have to integrate existing system monitoring, control, and protection systems with new measurement, analysis, and protection capabilities into the overall defense-in-depth strategy. All system elements have to be coordinated*".

The essence of this recommendation is to ensure that all real time monitoring, control and protection of transmission and generation elements be coordinated. While synchrophasors are playing a larger part in the monitoring of the power system, there are applications in protective relaying and special protection schemes where synchrophasor technology could and should be used. It is the intent of this paper to champion synchrophasor technology for special protection schemes, but there is a vast area of research that needs to investigate an integrated approach to monitoring, control and protection that utilizes synchrophasor technology. See Appendix A for detailed recommendation from the August 14, 2003 disturbance report.

2.2 Task 2 Report

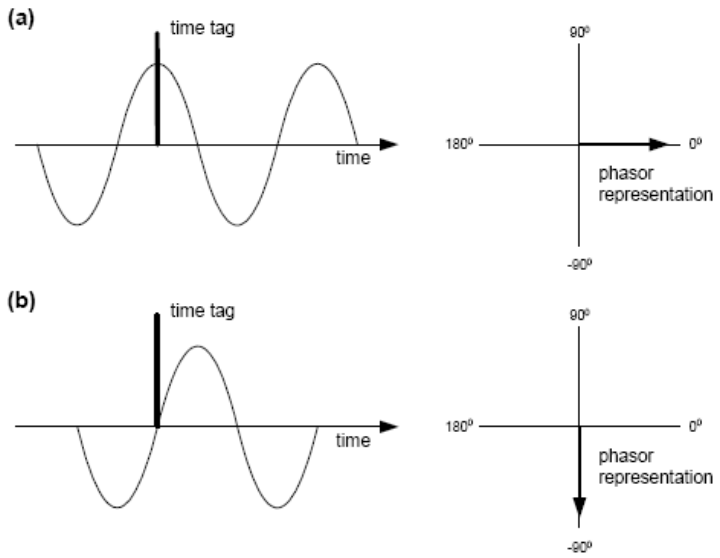
2.2.1 Background

The industry first started developing synchrophasor technology around 1988. Arun Phadke was a pioneer in this effort in 1988 at Virginia Tech where some of the first prototype phase angle measuring units that were synchronized to an internal time clock were built. The installation of Global Positioning Satellites (GPS) allowed the measurement of phase angles to be synchronized to a very accurate time clock. Macrodyne started building some of the first commercial pmu/synchrophasors in the late 1980s. The WECC (primarily BPA) started installing pmus in the early 90s and was the basis for WAMS. A lot of that data was very instrumental in analyzing the 1996 system disturbances in the West. EIPP (Eastern Interconnection Phasor Project was formed after the August 14, 2003 blackout. EIPP and WAMS were combined into NASPI just recently to have a consistent focus on the synchrophasor technology.

2.2.2 Basic Theory of Synchrophasors

The theory behind synchrophasors, or synchronized phasor measurements, is to provide a phasor representation of a power system voltage or current to an absolute time reference. When this is done, the voltage or current waveform can be defined as a complex phasor with a phase angle (as compared to a time reference) and magnitude. An internal high accuracy clock which is synchronized to coordinated universal time (UTC) via a Global Positioning Satellite System(GPS) provides the time tag or absolute time reference. As seen in figure 1 then the voltage waveform can be defined as a phasor with a phase angle and magnitude. The phase angle is measured by comparing the peak of the sinusoidal wave form to the time tag. Figure 1a shows the peak of the waveform corresponding to the time tag so the relative phase angle is 0 degrees. In figure 1b the peak of the waveform compared to the time tag is 90 degree. If for instance the voltage waveforms represented in figure 1a and 1b were at different substations it would indicate the amount of real power that could be transferred between the substations. Without a synchronized time standard the relative phase angle difference between the two substations wouldn't mean anything.

Figure 1.1: Synchrophaser Definition and Angle Convention



By installing synchrophasors at a select number of important substations, the power system engineer can immediately know the amount of real and reactive power flowing between the substations. The difference in phase angle causes real power as measured in MW to flow and the difference in voltage magnitude causes reactive power as measured in Mvar to flow. Knowing enough of the steady-state real and reactive flows along with voltage and phase angle can substantially aid "state estimation" programs which is the basis for all advanced power flow and contingency analysis programs in EMS (energy management system) centers. Knowing the rate of change of angle and voltage will determine whether the power system is nearing instability and whether the system will recover from an outage of a major transmission line or generator. So this technology can be used either as a tool to estimate the state of the system or as tool to take remedial action in the case of an outage.

2.2.3 Synchrophasor Standards

The IEEE (Institute of Electrical and Electronic engineers) defines many standards throughout the industry. They defined standard 1344-1995 which was approved in 1995 to set standards for synchrophasor measurements and communication protocol. They recently updated the standard in 2005 under a new standard C37.118-2005. This new standard defines measurement convention, measurement accuracy and communication protocol. For PMUs to be compliant with the standard, they must meet the synchrophasor accuracy standard, conform to measurement convention and conform to communication protocol for reporting measurements.

The new standard specifies that PMUs must be less than 1 percent error considering the aggregate of timing, magnitude and angle error. For instance if there were no timing or magnitude errors, the maximum allow angle error would be .573 degrees.

The convention for measuring phase angle is depicted in figure 1 above. Also to meet the standard, a PMU must provide a sampling rate of 10 reports per second up to half the nominal frequency which in this country is 30 reports or samples per second. PMUs must also provide estimates of frequency and rate of change of frequency as part of the PMU output data stream. Even though there is no standard on how this is to be calculated, the PMU should be able to do this very accurately.

The standard defines how communication is handled between a synchrophasor device and a Phasor Data Concentrator (PDC). A Phasor Data Concentrator archives and presents data to various applications. This protocol can be used to define exchange information between PDCs.

To be compliant with the standard, PMUs must meet the minimum requirements but there is nothing to prevent the manufacturer from adding additional features such as noise suppression, filtering and better accuracy. Data from PMUs made by different manufacturers should be compatible.

2.2.4 Areas of Concern and Areas for Further Development

Communication latency, performance under dynamic conditions, aliasing and instrument transformer errors are areas that need to better defined and better understood when applying synchrophasor based protection schemes.

Depending on the application, communication latency may or may not be a major concern. If synchrophasors are being used to enhance state estimators or to provide alarm or data trending to the operators, then the delay in communication signals is not a big concern. If on the other hand synchrophasors are being used in Special Protection Schemes, out-of-step schemes or for applications where dynamic/transient instability is involved, then communication delays are a major concern. Communication delays can be categorized into the following areas:

- Fixed time delay – instrumentation transformers, analog and digital filtering, signal processing, data concentrators, etc.
- Propagation delay – the inherent time delay of link and physical distance which the data has to travel.
- Transmission delay – Amount of data to transmit and the data rate.

The time delay could add anywhere from 100 to 300 microseconds based on the communication medium and physical distance that the data has to travel.

Synchrophasor standard C37.118-2005 intentionally does not address the performance of PMU devices during transient conditions. The next update of the standard will address this but for now it is something that the individual manufacturers must decide on they address it. High speed protection schemes that protect against instability would have to address this on an ad hoc basis for now.

C37.118-2005 addresses interfering frequencies and phasor aliasing briefly. It addresses the Nyquist theorem which states that to properly detect and display a desired frequency the sampling frequency must be at least twice the desired frequency. So i fa frequency of 15 Hz was

to be monitored the sampling frequency would have to at least 30 Hz. The WECC has standardized on a sampling frequency of 30 times a second so detecting frequencies below 15 Hz should not be a problem. Since the oscillation frequencies in the West vary from .25 to .7 Hz, this is not a major issue. The standard also addresses "interfering frequencies" by suggesting that appropriate "anti-aliasing" filtering be used to address the conflicting frequencies.

Current and potential transformers introduce some errors into Synchrophasor measurement. The more heavily loaded a current transformer is, the more error current in terms of excitation current that is produced. As most modern current transformers are designed to produce accurate secondary currents during faults, there is a greater percentage of error current produced during light load conditions. Generally a measurement error greater than .3 percent would not be expected. A greater concern in terms of performance is potential transformers. At the EHV (extra high voltage) levels, potential transformers are mostly coupling capacitor transformers and can produce errors of 1 percent or higher. During transient conditions, potential transformers are also prone to problems and this should be taken into account if Synchrophasor applications are being used for transient stability applications.

2.2.5 Synchrophasor Manufacturers

The following companies manufacture PMUs:

- Ametek
- Metatech
- USI
- Next Phase
- ZIV
- RFL
- GE
- ABB
- Siemens
- Schweitzer
- Arbiter
- Hathaway/Qualitrol
- Macrodyne
- Hitachi

The PMU manufacturers can be put into two groups: Those whose primary business are protective relays and those whose primary business is digital fault recorders, meters and monitoring equipment. From a technology standpoint it doesn't make any difference but it is interesting to see the different approaches. The primary relay manufacturers such as GE, ABB, Schweitzer, Siemens and Hitachi all make PMUs some as stand alone units and some that are integrated into the relay package itself.

For instance Schweitzer Engineering Labs philosophy is to provide PMU capability integrated into all of their modern relays. The SEL 421 and 451 relays are primary line and bus protective relays that have PMU capability integrated into the relay package. SEL offers customers firmware upgrade packages for the SEL 311, 321 and 351 relays that provide full PMU functionality. Mr. Schweitzer's vision is to provide PMU capability in all of their relays at no extra cost so that the end use customer will be able to utilize synchrophasors for any application including state estimation, real time metering and special protection applications. Many protection engineers have expressed concern about including PMUs as part of the primary relay package. Their concern is that the PMU design will compromise the performance of the relay. There is no technical reason, however, why there should be any loss of accuracy or quality in the relay as the PMU and relay are two separate packages. SEL has been very successful in the past in terms of packaging fault location functionality with primary relay functions and there is every reason to believe he can do the same thing with PMU technology based on their track ecord of thoroughly testing their product. Presently SEL has 15,000 relays installed with PMU capability across the country with a potential for 80,000 relays with PMU capability if the all of the older 300 series relays were upgraded by the customers.

GE is another major relay manufacturer that offers full relay and PMU functionality in the product line of Multilin relays. GE provides stand alone capability in their N60 as part of the UR (universal relay family). It fully meets the C37.118-2005 standard and provides a broad range of capability in addition the required features of the Synchrophasor standard. PG&E has plans to utilize the N60 relay as part of the upgrade to the Pacific Intertie RAS/SPS.

Arbiter, MehtaTech, Macrodyne and Qualitrol are PMU manufacturers whose primary focus is on digital fault recorders, monitors and PMUs. Some of them may make ancillary relays and associated equipment but they are not viewed primarily as relay manufacturers.

2.2.6 Key Findings

- Of the major relay manufacturers, Schweitzer, ABB, Siemens and GE manufacture PMU/sychrophasor products.
- Arbiter, Macrodyne and Hathaway manufacture PMUs as part of their product line.
- Schweitzer has adopted the philosophy of providing PMU technology integrated into his latest digital relays such as SEL 421 and 451. Years earlier he provided the same functionality with fault recorders that were well received by the industry.
- Protection engineers are skeptical about using the PMU functionality when incorporated into the same relay box.
- Existing IEEE standard C37.118 does not address the dynamic performance of pmus.
- To utilize PMUs over a wide area, communication latency is a major issue. The time delay to communicate phase angle from different locations cannot be greater than the time it takes for instability to occur.
- All RAS and SPS schemes today are prescriptive. In other words for a given set of conditions, the SPS will take specific action regardless of how stressed the system is.

More sophisticated RAS/SPS schemes incorporate tables that monitor actual system conditions and take action according to the table.

- A major next step to take would be to apply computer logic based on signals from PMUs to take action to avoid a reliability problem.
- There are data error and aliasing issues with existing pmus. Not all pmus perform the same.
- Instrument transformer accuracy impacts the accuracy of the synchrophasor.
- C37.118 does define the performance of pmus during off-nominal frequencies.
- C37.118 allows for different sampling rates. In the WECC, the sampling rate has been standardized at 30 samples per second.

2.3 Task 3 Report

2.3.1 Introduction

This section describes various research and development activities in the realm of Intelligent Grid Protection Systems. At this point in time when various technologies are being introduced into the grid, there is no clear definition of either 'Intelligent Grid' or 'Intelligent Grid Protection System.' It is generally understood that Special Protection Schemes (SPS) or Remedial Action Schemes (RAS) that have been installed in various systems around the world are Intelligent Grid Protection Systems because they surpass the functionality of the more common Protection Systems whose only purpose is to protect certain specific pieces of equipment from harm.

SPS/RAS usually has a couple of features that distinguishes it from simple protection schemes: (1) it usually will have more than one input or one output signal often from or to more than one location (substation), and (2) it usually will have a logic that will be more complex than used for simple protection schemes. Because of these features the boundary between protection and control is now quite fuzzy and there is no clear line between SPS and wide area control (WAC).

As pointed out in the Task 2 Report a major evolution in the grid today is the availability of real time data across the grid at much faster rates that are time synchronized. Although unique SPS has been implemented for some time utilizing specific real time data points and specific logic, the prospect of universal availability of synchrophasor data across the interconnection has brought about a qualitative change in the potential for 'intelligent' grid protection and control. In this Task 3 Report, we try to summarize all the various R&D activities that intend to utilize such synchrophasor data for the operation and control of the grid.

2.3.2 Background

Almost all the protection and control systems on the grid – and these number in the tens of thousands – almost all are local, i.e. the input variables and the output variables of each protection or control scheme are limited to within one substation. All common forms of protection fall into this category and all controls such as governors, voltage regulators, power system stabilizers, transformer taps, reactor bank switching, various FACTS devices, etc. are in this category as well. Only the following existing controls can be considered to be 'wide-area':

Special Protection Schemes (SPS) – This is a class of protection/control that has been used around the world to alleviate particular limitations in the grid. (The accepted generic name for this class is Special Protection Schemes (SPS) but because they have been utilized more extensively in the American West than anywhere else, the local name Remedial Action Schemes (RAS) is still commonly used.)

Automatic Generation Control (AGC) – The secondary portion of this control utilizes all generator outputs and all tie line power flows for the control area as inputs to control the governor settings at the generators so that generation and load are always in balance. The primary portion is the local governor control. (Nomenclature is again a problem for this control function as it has been called Load Frequency Control (LFC), Load Following, and more recently Load/Generation Balancing.)

Secondary Voltage Control – This is a secondary voltage control scheme to control the voltages in a local region and is superposed on the usual local voltage controllers like voltage regulators, transformer taps and shunt reactor switchings. It has, so far, only been used in Europe (France, Belgium, Italy). The first one is known as 'protection' because the action taken is fast – often in milliseconds – which is in the protection time-scale. Moreover, it uses real time input data that is updated at fast (protection type) time rates. Also the output signal often is the opening or closing of breakers which is what protection systems normally do. Finally, the SPS is triggered only when something happens, like a protection system, and is dormant otherwise. The other two are called 'control' because they work continually to adjust outputs and they work at slow speeds utilizing real time data at SCADA speeds. What is being anticipated now is fast protection and control of many different types, i.e. controllers that would operate at fast speeds utilizing synchrophasor data. We describe some of the R&D that is being conducted to develop various applications utilizing synchrophasor data.

2.3.3 Synchrophasor Data Applications

Obviously, a major application of the synchrophasor data is the various possible engineering analyses that can be conducted with this data, not the least of which is the post-mortem analysis of small and large disturbances. The post-mortem analysis of the 2003 Northeast blackout would have been a lot easier if more synchrophasor data were available and the little that were available turned out to be invaluable. However, the focus of this report is the operation and control of the grid in real time, so only those applications pertaining to operation and control are mentioned here. These applications can be broadly categorized into three types:

Monitoring applications

The operative phrase today is the situational awareness of power system operators. All the alarms and displays in the control center are driven by SCADA data which is updated relatively slowly – every few seconds – and the data is not synchronized. The synchrophasor data can then be utilized to better these displays and alarms in many different ways.

The most obvious monitoring that synchrophasor data can provide not available today on the SCADA is that of phase angle differences across key transmission lines or corridors. This is already available in many control centers although the displays are often not yet integrated

with the SCADA displays. Obviously, many types of displays and alarms can be generated from these phase angle differences.

An extension of this is to obtain phase angle differences between nodes that are in different control center jurisdictions. The problem here is not one of synchronization as all synchrophasor data everywhere are synchronized to a universal clock, but one of data transfer between one jurisdiction and another. Usually control centers exchange data at a very slow rate – slower than the SCADA sampling rates – and are useless for this purpose. However, both the Western and Eastern Interconnections have set up data transfer mechanisms between the synchrophasor data concentrators and these do provide data to far-flung control centers in near real time.

A second application has been the detection and identification of slow oscillations. The SCADA data sampling is too slow to detect such oscillations but synchrophasor data is fast enough for this purpose. Moreover, a Prony analysis of this data can actually calculate the frequency and damping of such oscillations. If an oscillation of known mode is detected and identified and it has low damping, operator initiated control actions can be used to damp out the oscillations. This type of situational awareness tools are already being used at Southern California Edison and Bonneville Power Administration using the WAMS. In the Eastern Interconnection PSERC has a research project to develop similar tools for Entergy and TVA although the problem of oscillations in the Eastern Interconnection is relatively new.

A third application for this monitoring data is visualization (which has become almost synonymous with situational awareness). The phase angle differences can drive displays that in some instances can provide more and different information than power flows. But more than that, the fast sampling of other analog data also provides the precise sequence of events (breaker operations), information on faults, and other transient conditions of the grid. Moreover, these can be obtained not just from the control center's own jurisdiction but from across the interconnection if necessary. Such visualization research work has been supported by PSERC and by USDOE through the CERTS program.

EMS applications

The exchange of SCADA data over ICCP links between control centers has made it possible for the system operators in one region to monitor happenings in their neighbors' systems. This provides good information about the present conditions of the interconnection in near real time to the operators. However, this does not in itself allow the operator to assess the ability of the grid to withstand the next contingency. To do this the operator needs the local control center to have a state estimator that has its reach beyond its own boundaries.

The traditional state estimator in a control center limited its model to its own jurisdictional boundary because the SCADA data were available only from those substations within its own boundary. The rest of the interconnection was represented as an external model which was a good representation of the static network but was highly erroneous because of the absence of real time data from this external system. These errors in the state estimator affected the results of the contingency analysis especially if the contingency was to happen outside the local jurisdiction or even near the boundary. This problem was particularly highlighted in the 2003

Northeast blackout as most of the operators in the outaged system were not aware that the next contingency several jurisdictions away would black out such a vast area.

Interconnection-wide monitoring and EMS functions (contingency analysis) have been recommended by a DOE/FERC report from last year, and various R&D and implementation efforts are underway. In the implementation arena, most efforts are using the SCADA data that are being exchanged between neighbors to widen the reach of each state estimator. In the Eastern Interconnection there are efforts between the ISOs in the Northeast (NEISO, NYISO, PJM), between PJM and AEP, between Entergy and TVA, and many others. Probably the most ambitious is the effort in the Western Interconnection where one state estimator model to represent the whole interconnection is being developed (known as the Western or WECC model).

The use of synchrophasor data in these state estimators is helpful in two ways. First, the data from the synchrophasors in steady state is usually more accurate thus helping state estimator accuracy; unfortunately the number of synchrophasor measurements in North America is still so miniscule compared to the system models that the impact on accuracy is negligible. Second, this data is synchronized unlike the rest of the exchanged SCADA data which has significant and unknown time skews and this helps the state estimator accuracy as well.

There are, of course, major issues with these various implementations. These exchanges of data are usually between the Reliability Coordinator and many of the Reliability Coordinators get their SCADA data through data links from their lower level Balancing Authorities. Thus the time skews between these data sets can be significant to the solution of the state estimator, whose accuracy, of course, affects the contingency analysis results. R&D is being conducted on these issues under various different topical names – distributed state estimator, hierarchical state estimator, external model, wide area model, etc. – but the main issue is how to provide a state estimate of the whole interconnection such that control centers can have access to a real time model of a large enough system that will give accurate predictions of its ability to withstand contingencies anywhere on the interconnection. Such research is being conducted at several universities under sponsorship of NSF, DOE and PSERC. In addition, the EMS vendors are tied to many of these R&D projects as they are all upgrading their state estimators to incorporate exchanged SCADA data and synchrophasor data.

Control applications

These applications are qualitatively different than the monitoring and EMS applications because both those types of tools are advisory to the human operator whereas control implies actual change made automatically to the system. Thus the demands for accuracy and correctness are far higher as non-operation or false operations could have drastic consequences.

Observation of the various SPS implemented around the world makes it clear that ad hoc wide area control applications are not only feasible but also very beneficial. We say that these are 'ad hoc' because each SPS implementation is unique in its design, implementation and the problem it addresses. As a result, each implementation is also expensive and because it solves a particular system problem, the SPS usually becomes obsolete in a few years as the system

changes and the problem disappears. An example may be an SPS to handle a regional voltage problem which disappears when new generation sources become locally available.

Thus R&D in this area follows two different but parallel tracks: one is the need for the upgrading of the power system infrastructure – computers, communications and controls – that will make it easier and more flexible to develop, design and implement wide area controls; the other is the need to develop control applications for specific phenomena that limit the operation of the grid. In the following section, these two tracks are explored in more detail.

2.3.4 R&D in Wide Area Control

There are significant economic incentives to increase the transmission limits of existing systems. In fact, the major constraints of the deregulated power markets are the transmission system limits. Today generation companies sell power to distribution companies (or directly to large customers) through bilateral agreements or auction markets. These transactions have to flow over the transmission system and if the transmission capacity was higher than all possible power flows such transactions may produce, then the market would be ideal. This, however, is not the case because the transmission system was built when the power companies were vertically integrated and they were sized for the expected power flows resulting from planned operation of the generators. The transmission system was not designed to accommodate all buy-sell agreements between generators and consumers.

Thus all power transactions must be checked before-hand to ensure that the flows are within limits. As there may be hundreds of simultaneous transactions between generators and consumers, and because the effects of these transactions on the flows are not linear, all simultaneous transactions must be studied together to check whether transmission limits are violated. If congestion is expected, all the transactions cannot be allowed and different ISO/RTO have worked out procedures about how and which transactions will have to be cut back. The procedures have to be fair to all parties and agreed upon beforehand. The reliability of the region rests with the Reliability Coordinator who has the final say on congestion management.

So the transmission limits are the constraints that also limit the power markets. For systems that are thermally limited, the only way to raise limits is to build more transmission. For those systems that are stability limited, better controls could increase the stability limit. Thus our interest in this paper is on better control of stability.

2.3.5 Infrastructure R&D for Wide Area Control

Essentially, there are three classes of technologies that are relevant:

- -Faster, cheaper computers,
- -Broadband, cheap communications, and
- -Better power electronic controls (also known as FACTS – flexible AC transmission systems – which covers this class of technology specifically developed to control the AC power system).

Some of these technologies are already in use in the power systems as mentioned in Section 2. What we are proposing here is the development of new controls utilizing a combination of these technologies. These controls will be significantly different in concept than the existing ones, and will be fast and system-wide to dramatically increase stability limits.

Computers

Computers (or microprocessors) are embedded in everything – meters, protective relays, data concentrators, communication switches. They are programmable, that is, the functions of the gadget in which they are embedded can be changed by software. Thus controls that utilize these components can be adapted, through changed settings (simple) or changed logic (more difficult), providing flexibility in the design of this software.

Workstation computers are also much faster and cheaper. Thus very large amounts of calculations can be done very quickly. Such analysis can then be part of the control bringing even more intelligence into the control loop. For example, if a control is devised to shed load to avoid instability, an optimal power flow could determine which loads are to be switched off.

Communications

Electric power companies have always had their own communication systems. This has mainly been microwave channels that connect every substation and generating station. The use of optical fiber is now increasing at a tremendous rate. At first, the optical fiber has been used within substations and generating stations, especially the newer installations, but the older ones are being rapidly retrofitted. This is being done to gather more real time data at faster rates at the substations so that fast appearing emergency conditions – like right after a lightning strike – can be better protected against. The data can also be captured but has to be stored locally to be later transmitted over communication networks.

Optical fiber has also been strung along transmission towers. Power companies mainly did this to become communications providers because of the projections of ever-increasing demand for bandwidth. Although this venture into new business has not panned out because of the glut of unused bandwidth, a broadband network is now easily available to the power companies. If this network bandwidth is broad enough, then all the data being collected at the substations can be transmitted in real time to other locations like the control center. In fact, a network can be envisioned such that the real time data would be available to different computers depending on their function. This opens up the possibility of decentralizing the control center so that functions can be put in different places depending on where it is needed. With a network like this, the stark differentiation today between centralized control and local control would go away and controllers could use the most appropriate data needed for control.

A communication network that can meet the varied needs for the operation of the power system would be much more complex than the simple star network used today for the control center to poll substation RTUs. Moreover, the control functions will not be all concentrated at a central computer in the control center but would be distributed over numerous computers whether they are in substations, generating stations or engineering offices. Such distributed computer communication is being developed today for various applications. In such a communications

network some of the functions (measurements or calculations) will be publishers of data while others who will use this data (applications, controls) will be subscribers. The network will be controlled by other computers that will be quality of service (QoS) managers. Such middleware are being developed for other applications and will have to be developed for the architecture appropriate for the power grid. It should be mentioned that, given the concern for the security of such critical infrastructures as the power grid, such computer communication systems for the power grid must be secure from external intrusions and has to be built into the QoS.

FACTS

FACTS devices available today were discussed in Section 2. Although they are different in detail by model and manufacturer, but they fall into three classes:

- DC transmission controls,
- SVC (static var controller), and
- PFC (power flow controller).

In addition, special controllers can be built for specific purposes using the same principles. One major advantage to these controllers is their speed with control actions taking place in milliseconds which is in the same timeframe as protection actions.

2.3.6 R&D in Control Applications

The proposed control concepts described here are all wide-area controls. Although local controls continue to be improved using newer technologies, the conceptual functionality of these local controls will remain the same. The wide-area controls presented here will often take care of the local controllers but the main objective is to improve the overall stability of the power system. The concepts are presented in the order of increasing complexity, also implying that the ones presented first would be easier to implement.

Frequency Control

As noted before, frequency is controlled by balancing load with generation. The primary governor control at the generators is local while the secondary AGC control that adjusts the governor setpoints is area-wide. The primary control is continuous whereas the secondary control is discrete usually using 2-4 second sampling.

Given that all generators in a region are no longer owned by the same organization, this area-wide AGC control will become more decentralized. The Federal Energy Regulatory Commission (FERC) ancillary service regulations do allow third-party AGC but a new communication-computation-control scheme needs to be developed. As this control is quite slow (2-4 second sampling), feasibility of control is not a problem. The more complex communication scheme required is also not a problem; although a meshed communication network is required rather than the present star network, the bandwidth requirement remains modest. However, such a network introduces other modes of failures like signal delays and the control have to be robust enough to handle them.

Regional Voltage Control

Voltage control in North America has always been local, although Europe is trying some regional control schemes. FERC recognizes voltage-VAR control as an ancillary service. Control schemes for such regional control need to be developed but the schemes have to be such as to ensure that such service can be quantified and paid for as an ancillary service. This type of control, like frequency control, is relatively slow and so the feasibility of the control and communication is not an issue. The main hurdle has been the selection of input and output variables of the controller that can handle all the varied operating conditions that the power system endures. Thus this challenge is a classical one of developing a practical robust controller.

Small signal stability control

Small signal instability occurs when a system perturbation, even a small one, excites a natural oscillatory mode of the power system. These oscillations are slow, usually under 1Hz. The main method used today to guard against small signal instability is the off-line tuning of power system stabilizers (PSS). These PSS are local controllers on the generators. Thus local controllers are used to mitigate system oscillation modes, a procedure that is recognized to have significant disadvantages. New controllers need to be developed that can use system-wide inputs (not necessarily more inputs per controller but input signals from further away). Such remote signal inputs will obviously require communication channels which could be dedicated or could use a more flexible communication mesh network.

Another control concept is to adaptively change the PSS setpoints according to the power system operating conditions. This would be analogous to the AGC control by introducing a secondary control scheme that would periodically adjust the setpoints of the local PSS controllers as the system changes. The challenge here is that the calculation of PSS setpoints requires large analytical calculations, which are today done off-line but will have to be done on-line in this case. The speed of calculation is not a major concern as changing the setpoints can be done quite infrequently, probably minutes.

Voltage stability control

Voltage instability occurs when a change in the power system causes an operating condition that is deficient in reactive power support. Guarding against such instability requires the anticipation of such contingencies that can cause voltage instability and taking preventive action. New preventive control schemes are needed that can also include special protection schemes that could isolate those areas with var deficiencies.

This is not a stability control in the traditional sense that responds to a disturbance. This is an action plan to ensure that the system operating condition does not stray into an area where a perturbation can cause voltage instability. The control of the transient condition after a disturbance occurs is handled in the next section.

Transient stability control

The development of such a control scheme is by far the most difficult because a disturbance that can cause instability can only be controlled if a significant amount of computation (analysis)

and communication can be accomplished very rapidly. This concept is approached in three increasingly difficult levels:

- the first is to use off-line studies to manually adjust protective schemes which would operate only if the disturbance occurs;
- the second is to automatically adjust these protective schemes with on-line calculations;
- the third and final would be to directly operate the control actions after the disturbance occurs.

'Soft-wired' remedial action schemes

A step advance in this direction will be to generalize remedial action schemes (RAS), also known as special protection schemes, to control transient stability. These RAS today are developed from the results of voluminous off-line studies and are implemented with a 'hard-wired' communication system. Thus, the system values and statuses monitored and the breakers controlled cannot be modified. What is proposed here is the development of a generalized communication system that can enable the implementation of new remedial action schemes by software modification. Although a comprehensive communication scheme will be required in this type of control, the computation requirements will be modest as the control schemes are largely defined off-line.

On-line setting of remedial action schemes

A step forward will be to develop methods to control transient stability but with less dependence on off-line studies and more use of on-line computation. The main idea here is to use more real-time data to determine what control is needed. What is proposed here is the development of soft-computing techniques using pattern-recognition, neural-networks, expert systems, etc. to process the real-time data to decide the best control action. Of course, much off-line training of the software may still be required off-line but the expectation is that the control action would be much more efficient than those purely decided off-line.

Real time control of transient stability

The objective here is to develop a global control for transient stability (with no off-line assists). For this to be feasible, the computation needed to determine the disturbance scenario and then computing the necessary controls for stabilization, has to be in the same time-frame as today's protection schemes (milliseconds). Whether this is indeed possible with today's technology is not known. However, the goal here would be to determine what kind of communication-computation structure will be needed to make this feasible.

2.4 Task 4 Report

2.4.1 Background

All three investor owned utilities, PG&E, SCE and SDG&E use RAS/SPS schemes to mitigate overload, voltage and stability problems. PG&E and SCE utilize special protection schemes to mitigate reliability violations as the result of multiple contingencies when it is impractical and very expensive to build transmission and/or generation projects. In some cases the special

protection schemes buy time before a transmission or generation project can get installed. On virtually all of the major transmission paths importing power into California such as Path 66 (California – Oregon Intertie) or facilitating inter-area transfers between Northern and Southern California (Path 26 and Path 15) special protection schemes are used to protect against unlikely contingencies that could result in a system wide blackout.

These special protection schemes use a range of control actions to mitigate the impact of the contingencies but under worst case scenarios they all drop some combination of firm load and generation to prevent instability and to maintain a reasonable load/resource balance. The inherent problem with all of these schemes is that they are designed to be prescriptive in that worst case scenarios must be assumed to prevent catastrophic results under heavily loaded conditions. This means that there are a range of conditions where more load and generation is tripped than necessary to prevent the catastrophic outages from occurring under very stressed conditions. Under a vast majority of conditions where loads are lighter, the remedial actions are either unnecessary or far less load and generation would need to be tripped. Conversely there may be times when more capability is available than anticipated because the system is less stressed. Conventional special protection schemes do not have the intelligence to detect this, but synchrophasor based special protection schemes will have the intelligence to determine there is more capability in the system and take advantage of this. It should be noted that "Total Transfer Capability (TTC)" can't be exceeded but additional capability under nomogram operation could be utilized.

Given the technology of ten years ago there was no choice but to design these prescriptive types of schemes. Today Synchrophasor (pmu) technology makes it possible to design schemes that take appropriate remedial action based on actual system conditions. While some at PG&E and SCE have plans to utilize this new Synchrophasor technology, it is still a "leap of faith" to do so when there are no proven schemes in service in the United States using this technology in a practical application such as a special protection scheme.

2.4.2 Issues in Intelligent Grid Protection

In this Task 4 Report we recommend an R&D plan. The plan starts out with general R&D issues which will require longer term R&D to properly develop this whole area of Intelligent Grid Protection. It also looks at possible demonstration projects and recommends a particular one in California.

One can essentially think of the first SPS/RAS schemes as the start of Intelligent Grid Protection. Although the earliest such implementations were quite simple, conceptually they were different from the traditional protection of individual pieces of equipment. In addition to isolating the short circuit locally, other control actions were needed to protect as much of the grid operation as possible. These SPS/RAS schemes have become more sophisticated over time and can use a variety of inputs from several substations and can send control outputs to several control equipment in more than one substation.

It is fair to state that all the hardware technologies needed for Intelligent Grid Protection are already here. These include various sensors and measurement technologies, the latest being the

synchrophasors or PMUs that are nothing but the measurements of ac values at high rates of sampling that are time stamped with the absolute time standard. They also include high speed communications that are needed to move measurement and control signals. Finally, they include fast circuit breakers and other controllers (mainly FACTS devices).

Thus, a standard design process for such intelligent protection schemes has developed that goes something like as follows:

- Have a good idea
- Test on simulations
- Design the prototype:
- Measurements needed
- Point-to-point communications needed
- Controls needed
- Install and test on real time data
- Close the loop

Each SPS/RAS scheme is a unique implementation, separately designed, tested and implemented. As is true for any unique system, implementations of SPS/RAS systems are expensive. In addition they are not easily modified as modifications have to follow the same design process as the original design. This is significant because the lifetime of a SPS/RAS scheme may be limited by the fact that the power system is being continuously upgraded with new transmission, generation and other protection and control.

Certain infrastructural improvement in the power system could make this design process simpler and hence, over the long run when such intelligent systems proliferate, the cost of implementation would be much less. Such infrastructure improvement consists of hardware, software and methods as follows:

Communications infrastructure

- Networked, high-bandwidth
- User-friendly applications level middleware
- Detection/identification algorithm development

Controller design process

- Determining best inputs, outputs
- Developing output calculations

Off-line testing methods

- Nonlinear, digital simulations

Obviously, the availability of *networked, high-bandwidth communications* will eliminate the need for leasing point-to-point communication links for each SPS/RAS scheme. Although the initial cost of such a communication network is high, it can be amortized over many, many

applications. This can be looked upon as the successor to the microwave network installed by the power companies in the 60s. In any case, fiber optic cables exist along many transmission corridors and can form the backbone of such a network. The bigger expense is the *applications level middleware* needed to run such a network in a flexible way that will make the implementation of SPS/RAS schemes very simple.

The triggering mechanisms for these intelligent schemes are important and new methods need to be developed. Of course, short-circuits are easily detected (because of the high currents) and have been used routinely to trigger relays but for the new intelligent schemes other triggering mechanisms may be more important, e.g. phase angle difference or voltage magnitude. Thus *detection* of various triggering conditions and the *identification* of which condition is detected require methodological development.

A major drawback to the design of any SPS/RAS scheme is that there is no standard *design process*. Each phenomenon that requires some special protection action is considered a special problem that requires an engineered solution. It is hoped that for certain classes of phenomena, say low frequency oscillations or voltage dips, some best practices for a design process will emerge. Such a design process may consist of determining which *input variables and/or output control variables* work the best under most circumstances. Also, best algorithms to *calculate the output variables* need to be developed.

A major step in designing such intelligent schemes is the simulation step. In fact, *simulation is the main tool* that determines the effectiveness of any scheme before it can be tried out on the real system, which is always a risky step. The problem is that such simulation tools are not readily available. The best tool available today as production grade software is the transient stability program, which has two major drawbacks. One is that it is difficult to model all the existing protective relays which is very important to do because the intelligent systems operate in the same time frame. The other is the absence of the model of the substation structure – transient stability and power flow programs use the node-branch model and not the bus-breaker model of the substation – which is usually important in representing protection schemes. Thus better and more appropriate tools are urgently needed for the encouragement of such intelligent protection.

In the following sections we discuss several of these infrastructural issues that require significant R&D before intelligent grid protection becomes commonplace.

Measurement data issues at the substation

Every high voltage substation today has a very large number of instruments that measure and gather data. They are microprocessor based and are used for protection, fault detection, recording sequence of events and a myriad of other purposes – and are generically known as IEDs. Unfortunately, they all measure at different sample rates, at different accuracies, and store the data at different rates in different storage devices. A few are time stamped by using a GPS connection and most are not. Some of this data is available over communication channels to remote locations and some are not. Although there are now communication standards, there are no overall standards for sampling, accuracy, storage, etc. R&D is needed to determine how best

to consolidate this data so that it can be flexibly accessed by various applications including intelligent grid protection.

Data issues at the regional and interconnection level

The grid spans many jurisdictions. For example, in the Western Interconnection there are three Reliability Coordinators that look after three regions of the interconnection and under these Reliability Coordinators are about 40 Balancing Authorities, each gathering data from their substations into their control centers. Thus data is being moved from the substations to the Balancing Authorities and up to the Reliability Coordinators. However, this data is the SCADA data which is collected at a relatively slow sampling rate – about several seconds – and are not time stamped. What will be needed for intelligent protection is data collected at much faster sampling rates at the substations and then moved at much faster rates, with small latencies, across the interconnection. The need for high-speed networked communication between substations is obvious but the actual design of such a communication system – both architecture and middleware – requires much R&D.

Design process for the Intelligent Grid Protection System

As intelligent grid protection refers to a large class of protection systems, it is unlikely that a single design process will emerge that will be able to produce such a special protection scheme for any particular problem. However, some best practices will probably arise for particular classes of phenomena. For example, low frequency oscillations are a problematic phenomenon in the western interconnection. However, detection and identification (of frequency mode and its damping) in real time has not been particularly easy even though it is relatively easy to do so using post-disturbance stored data in an off-line calculation. But variations of the off-line analysis tools have been tried with reasonable success. Much R&D is needed to continue developing such "best practice" algorithms for various phenomena that can be controlled by intelligent protection schemes.

Input/output signal path issues

Unlike traditional protection schemes which use local inputs and local outputs, i.e. the input signal and the control signal are within the same substation, intelligent grid protection implies input signals and output signals that may travel long distances from and to many substations. Since these are necessarily digital signals traveling over communication channels, their sampling rate and latency impact the effectiveness of the control action. Thus the design process for the scheme must also take into account the sampling rate and possible latencies, both of which can have uncertainties (i.e. they are not fixed and are affected by other data flow on those channels). R&D is needed to handle such data flow issues as part of the design process.

Simulation testing

None of the production grade simulation packages used today to simulate the grid – transient stability and power flow programs – is quite adequate for simulating these intelligent protection schemes. A major drawback in these simulations is that the modeling of the grid is much simplified: (1) the balanced phase single line model does not pick up the imbalances that may

affect protection schemes, and (2) the node-branch model misses the detailed substation configuration that always affects protection. Although most of the nonlinearities are well modeled in the present simulations, discrete controls are difficult to model, but any protection scheme using data from remote locations must be able to represent sampled (rather than continuous) data and possible latencies. R&D (especially D) is needed in developing such simulation tools so that the testing of intelligent protective schemes becomes more reliable.

2.4.3 Potential Demonstration Projects

The project team has had extensive discussion with both PG&E and SCE regarding the scoping of a potential project demonstrating Synchrophasor/pmu technology. PG&E has installed several new special protection schemes such as the San Francisco, Metcalf and Diablo Canyon SPS in the last several years to protect against unlikely contingencies that would have serious consequences should they occur. All of these schemes involve local area generation that is dispatched economically and that also has an impact on the local area reliability.

For instance PG&E's San Francisco RAS protects against loss of an entire substation with multiple buses and two different voltage levels which goes beyond NERC level D* planning. The San Francisco RAS uses GE's universal relay at multiple substations to do distributed processing and also communicate with centrally located fault tolerant programmable logic controllers. Even though SF RAS is a very sophisticated and state of the art scheme it still is somewhat prescriptive in that remedial actions are taken assuming heavily loaded conditions. Both the Metcalf and Diablo Canyon special protection schemes protect against multiple contingencies where there is a surplus of generation that either cause emergency overloads and stability problems. The Diablo Canyon special protection scheme was installed recently and incorporates pmu technology in the detection of the contingencies but it still takes prescriptive action in that a Diablo Canyon unit must be tripped under a wide range of conditions to protect against instability.

PG&E has plans to utilize pmu technology in the next generation special protection scheme for the California – Oregon Intertie. It's not clear what the specific plans are but there is an opportunity to take remedial actions based on actual system conditions rather than prescribing a remedial action based on worst case assumptions.

The project team has met with Southern California Edison (SCE) a number of times and had several conference calls with them regarding the application of pmus and special protection schemes. While SCE has several special protection schemes, the focus of the discussions has been around SCE's Big Creek project.

The Big Creek project is a 1010 MW hydro project east of the Fresno area. There are four 230 kV outlet lines that connect the Big Creek generation to the Southern California Edison system at Magunden and there are five 230 kV lines that connect Magunden to the SCE bulk transmission grid. The 230 kV lines and towers are original equipment built around 1912 and are small conductor high impedance lines. There are several substations along the way that serve load in the Visalia/Tulare area (Eastern San Joaquin Valley) and have an impact on the stability of the Big Creek generation. The load in this area has been growing at a substantial rate and

exacerbates transient stability and voltage collapse in the area. There is an existing contingency based RAS scheme that either runs back (ramps down) or trips generation in the Big Creek area depending on whether stable or unstable swings are detected. There also is an overload scheme that primarily protects the lines south of Magunden. The RAS scheme incorporates discreet relays to detect the presence of an unstable swings (Schweitzer 68 relay), whether there is a three phase fault at Magunden or whether there are overloads on the Magunden south 230 kV lines. The RAS scheme arms generation runback and generation tripping if loads are above 650 MW at Rector (major load station between Big Creek and Magunden). There is no generation limitation at Big Creek for loads below 650 MW at Rector.

In our discussions with SCE, they have indicated they have near term plans to replace the existing Big Creek RAS scheme with more modern relays and to upgrade the 230 kV transmission by adding a fifth 230 kV line between Big Creek and Magunden. Even with adding this line, they will still have stability problems in the future and will need to install an updated Big Creek RAS as early as next year. SCE also has plans to consolidate their high voltage intertie RAS schemes into a centralized RAS which they are calling their "C-RAS". Their vision is to incorporate synchrophasor technology into that application.

SCE has installed a pmu at Big Creek and has substantial bandwidth in their telecommunication infrastructure to allow high speed telecommunication between Big Creek and remote substations for RAS control. SCE's R&D personnel have developed innovative software called "SMART" that does synchronized measurement and analysis in real time. They have been able to review past WECC system disturbances and identified accurately the percent damping of the disturbance as well as the various oscillation frequencies. SCE's operation, R&D, planning and system protection personnel have indicated their support for a synchrophasor application project in the Big Creek area that would demonstrate synchrophasor technology.

2.4.4 Discussion

Both PG&E and SCE have the infrastructure and personnel to do a successful project demonstrating synchrophasor technology in a special protection scheme application. PG&E and SCE have installed a significant amount of pmus along with telecommunication infrastructure for the high speeds necessary for special protection scheme applications. There is little perceived difference between the capability of the PG&E's and SCE's operation and protection personnel. Southern California Edison has an edge in the R&D area as their personnel have invested significant time and effort in developing unique software that can analyze and detect grid oscillations. Also, SCE's planning personnel have an excellent vision for how to benefit from the synchrophasor technology as demonstrated by their vision for "C-RAS". Their operations, system protection, planning and R&D personnel are all aligned in supporting synchrophasor technology and application standpoint.

While both PG&E and SCE have potential projects for demonstrating synchrophasor technology, Big Creek has the infrastructure, range of RAS actions and need to be a nearly ideal project for applying synchrophasor technology. There is an SVC at Rector that could be switched on to improve stability and a number of generators at Big Creek that could either be tripped or run back as mitigating actions for stability problems. To differentiate between an

existing special protection scheme and a synchrophasor based special protection scheme, software must be written to take advantage of the technology. For instance in a sychrophasor based application the actual system conditions are known including actual phase angles between two specific substation locations, percent damping and modes of oscillation. Taking advantage of this would allow for less drastic action to be taken during less stressed system conditions and faster more appropriate action to be taken during stressed system conditions that could allow for more generation to be exported into the system

2.4.5 Recommendation

The project team recommends that PIER sponsor a synchrophasor demonstration project at SCE's Big Creek project to include the installation of a PDC, centralized programmable logic controller (plc) and the software to program the plc as a special protection scheme for the Big Creek project. We further recommend that this be done in parallel with SCE's RAS upgrade project. The demonstration project would be in the monitor mode and data could be analyzed from both projects to understand and improve upon. It is proposed that a 2008 budget item be established for this purpose.

CHAPTER 3:
Conclusions and Recommendations

3.1 Conclusions

To utilize synchrophasor technology in special protection schemes, the following issues must be addressed:

- Reliability of telecommunications network
- Latency of telecommunications network
- Accuracy of PMUs
- Performance of PMUs under stressed conditions
- Accuracy of CCVTs and CTs
- Identification of what action and when to take it
- Maintenance needs of PMUs

The following is the state-of-the-art in intelligent system protection technologies:

- IEEE standard C37.118-2005 addresses the performance of PMUs including off-nominal frequencies, accuracy and sampling rates but does not address dynamic performance.
- Both mainstream relay manufacturers and instrument/monitoring manufacturers make PMUs.
- Schweitzer Engineering Labs (SEL) manufacture a full line of protective relays that include PMU capability in the same relay package.
- Some protection engineers are skeptical about the reliability of using PMUs when incorporated into the same relay package.
- To utilize PMUs over a wide area, communication latency is a major issue. The time delay to communicate phase angle from different locations cannot be greater than the time it takes for instability to occur.
- All RAS and SPS schemes today are prescriptive in that they take specific action for a given set of conditions.
- The next major step is to apply computer logic utilizing PMU technology to take action based on real time conditions.

Following are ongoing system protection R&D related to wide area control:

- Transmission system constraints are the major constraints to a deregulated power market.
- Virtually all of those transmission system constraints are either voltage or transient stability.
- State-of-the-art control today involves FACTS devices that control DC lines, provide high speed var control (SVC) or control power flow control (PFC).

- Europe has been experimenting with regional voltage control as wide area control of voltage. Typically in North America, voltage control is done on a local level only.
- Small signal stability control is another area ripe for wide area control. Presently, power system stabilizers (PSS) are the only means of controlling low frequency oscillations (less than 1 Hz) in the Western United States. These local controllers are oftentimes tuned for local oscillation frequencies and not intertie oscillation frequencies. .25 Hz oscillations exacerbated conditions that led to the August 10, 1996 blackout on the Western United States transmission grid.
- Voltage stability control from a wide area perspective is another area ripe for R&D.
- Remedial action scheme (RAS) also known as special protection schemes (SPS) are used to mitigate transient instability after an initiating outage has occurred. The authors of this paper believe that this is a major area of research to exploit PMU technology to proactively manage transient stability from a wide area perspective before a major outage occurs.

The following are potential projects and areas to demonstrate intelligent system protection:

- PG&E's San Francisco RAS project is already an intelligent protection scheme that could be further enhanced by PMU technology.
- PG&E's Metcalf and Diablo Canyon special protection schemes are also candidates for an intelligent protection scheme.
- The California – Oregon Intertie remedial action scheme is another candidate for a demonstration project.
- SCE's Big Creek project offers a good choice for an intelligent protection scheme.

3.2 Commercialization Potential

It may be possible to commercialize intelligent grid protection systems, however the authors believe that the applications are primarily limited to large utilities and independent system operators and not likely to be commercialized. Many of the components of an intelligent grid protection system such as PMUs are made by several manufacturers that are either imbedded in digital relays or made as standalone devices, and therefore likely to remain the primary commercial opportunity.

3.3 Recommendations

The authors of this paper recommend the PIER sponsor a synchrophasor demonstration project at SCE's Big Creek project. While PG&E has very good potential demonstration projects, the authors believe that the Big Creek project offers the best opportunity because it is transient stability and voltage stability limited and there are several control actions that could be used to proactively prevent a major outage.

3.4 Benefits to California

California will benefit in the short term by increased reliability of generation at Big Creek. To the extent that Big Creek can be operated at higher levels of generation, more costly generation

can be backed down, saving Californians the incremental cost between Big Creek generation and more costly generation.

In the long term the knowledge gained from the demonstration project could be transferred to more complicated special protection schemes such as the California – Oregon RAS scheme. The potential for savings is very large assuming that more power could be imported into California at least part of the time. The cost saving would be the incremental cost between primarily thermal generation in California and very economic hydroelectric power in the Pacific Northwest.

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GLOSSARY

CAISO – California Independent System Operator

COI – California Oregon Intertie

CCVT – Coupling Capacitor Voltage Transformer

CT – Current Transformer

EIPP – Eastern Interconnection Phasor Project

EMS – Energy Management System

GPS – Global Positioning Satellite

NASPI – North American Synchrophasor Project Initiative

PT – Potential Transformer

SCADA – Supervisory Control and Data Acquisition

SVC – Static Var Compensator

WACS – Wide Area Stability and Voltage Control System

WAMS – Wide Area Measurement System

WECC – Western Electricity Coordinating Council

UFLS – Underfrequency Load Shedding

UVLS – Undervoltage Load Shedding

VAR – Volt Ampere Recative

RTDM – Real Time Display Monitor

AGC – Automatic Generation Control

SPS – Special Protection Scheme

RAS – Remedial Action Scheme

PSS – Power System Stabilizer

PMU – Phase Angle Measuring Unit

PDC – Phasor Data Concentrator

OTC – Operational Transfer Capability

APPENDIX A

August 14, 2003 Disturbance Recommendation

Evaluate and Implement "Defense in Depth" System Monitoring, Control, and Protection Measures to Slow Down and Mitigate the Severity of Cascades

Action Plan

NERC PC/OC executive committees should review the Recommendation below, and Technical Report to be issued this summer. Prior to NERC PC/OC winter meeting, by 11/18/05 complete New Recommendation review and establish proposed scope of work including vendor participation. At winter meeting NERC PC/OC to review and approve proposed scope including assignments to PC for overall plan, Protection task force, and OC task force for implementation.

Observation

During the blackout, a number of generator control and protection systems, and transmission system controls and protections systems, including UFLS systems, interacted, not always to the betterment of the overall system health and resiliency.

System monitoring, control, and protection systems are currently applied mostly on a transmission operator or control area basis. However, each Interconnection of the bulk power system is, in fact, a very large single system and should be analyzed, controlled, and operated as such.

An overall defense in depth philosophy and integrated strategy is needed to protect today's bulk power system from cascading blackouts. Such a system would have to integrate existing system monitoring, control, and protection systems with new measurement, analysis, and protection capabilities into the overall defense-in-depth strategy. All system elements have to be coordinated[1].

Defense-in-depth should incorporate elements such as:

Wide-area and local monitoring of system operating conditions

Wide-area, high-speed (phasor) measurements of overall system indicators such as relative phase angles across the interconnection and across major transmission interfaces

Monitoring of inter-area, slow-speed oscillations

Priority based alarm processing and complete

[1] There is a lack of overall coordination of Special Protection Schemes with primary protection systems, plant control systems and EMS. This is an area where further research needs to be done to identify primary areas where this is crucial.

State-estimation of existing system conditions, ensuring the operator's view of the system is unencumbered by monitoring discrepancies

Early-warning contingency analysis of the existing and potential system conditions to ensure adherence to limiting system conditions

Pattern recognition of operationally dangerous system configurations

Emergency operations plans for severe contingencies

Operator training, including severe condition scenarios, to enhance situational awareness during emergencies

Coordinated UVLS and UFLS systems

System restoration plans that are adaptable to conditions existing after an outage

Such a system should be constantly updated to reflect system topology changes, and to take advantage of technical advances in monitoring equipment, computer calculation capabilities, state estimation, contingency analysis, and digital relays.

Stimulation of research into this area is absolutely imperative.

Recommendation

For each of the Interconnections, a defense-in-depth philosophy and integrated strategy should be developed based on the characteristics of that interconnection to limit the impacts of potential cascading outages.