FINAL REPORT

CENTER FOR GRID MODERNIZATION

June 30, 2008

Work Performed under
Cooperative Agreement No.: DE-FC02-05CH11298

Submitted by:
Concurrent Technologies Corporation (CTC)
100 CTC Drive
Johnstown, PA 15904-1935

Technical Point of Contact:
Daniel R. Markiewicz
Director, Advanced Energy Programs
Telephone: 814-269-2786
Facsimile: 814-269-2631
E-mail: markiewi@ctc.com

Administrative Point of Contact:
Tamara Goller
Contracts Administrator
Telephone: 814-269-2442
Facsimile: 814-269-2499
E-mail: gollert@ctc.com

Submitted To:
Department of Energy
Chicago Office
9800 S. Cass Avenue
Argonne, IL 60439
Attn: Steve Waslo, DOE Project Officer

TABLE OF CONTENTS

	Page
1.0 PROJECT OBJECTIVE AND TASKS.....	1
2.0 DELIVERABLE / MAJOR MILESTONE STATUS.....	1
3.0 SIGNIFICANT EVENTS AND ACCOMPLISHMENTS	2
4.0 PROGRAM ACCOMPLISHMENTS.....	5
4.1 CGM Operations / GridApp™ Consortium	5
4.1.1 GridApp™ Consortium Management.....	6
4.1.2 Project Development, Execution and Tech Transfer	7
4.1.2.1 Core Project – Advanced Distributed Energy Storage – FirstEnergy	8
4.1.2.2 Core Project – Coordinated Control – DTE Energy	10
4.1.2.3 Core Project – Substation Engineering Modeling Tool (SEMT) – Southern California Edison	12
4.1.2.4 Sponsor Project – Advanced Capacitor Control System (ACCS) – CTC, Idaho Power, FirstEnergy	12
4.1.2.5 Sponsor Project – GenOnSys Phase II – Portland General Electric	15
4.1.2.6 Sponsor Project – GridSense LineTracker™ DataPAC Development – CTC, Southern California Edison, DTE Energy, Exelon.....	17
4.1.2.7 Sponsor Project – Radio Communicating Fault Indicators – Exelon.....	19
4.1.2.8 Sponsor Project – S&C TripSaver™ Development – DTE Energy	21
4.1.3 Database and Website Management	23
4.2 Advanced Technology Projects	24
4.2.1 Advanced Fault Analysis Software System for Distribution Power Systems (AFAS) – CTC.....	25
4.2.2 Distribution Wireless Communication Network – CTC.....	27
4.2.3 Integrated State Estimation Project for the Virgin Island Water and Power Authority – CTC, Georgia Tech, VIWAPA	30
4.2.4 Phasor Measurements Business Case Analysis at Southern Company – CTC, Southern Company.....	31
4.3 Program Management	34
5.0 FINANCIAL REPORT	36
6.0 CONCLUSION.....	36

TABLES OF FIGURES

Figure 1 – PowerBlock System Components	9
Figure 2 – Idaho Power WYEE Substation ACCS Equipment Diagram.....	14
Figure 3 – FirstEnergy Kenvil ACCS Equipment Diagram	15
Figure 4 – GridSense LineTracker™	18
Figure 5 – Preliminary FCI Model	20
Figure 6 – Physical Testing at DTE Energy Facility.....	23
Figure 7 – CTC's Wireless Mesh Network Concept.....	30
Figure 8 – Typical Substation State Estimator	31
Figure 9 – Business Case Analysis Process	32

1.0 PROJECT OBJECTIVE AND TASKS

Concurrent Technologies Corporation (CTC) operated the Center for Grid Modernization (CGM) to support the U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability (OE) in achieving its “Grid 2030” vision. The objective of the CGM was to develop high-priority grid modernization technologies in advanced sensors, communications, controls and smart systems to enable use of real-time or near real-time information for monitoring, analyzing and managing distribution and transmission grid conditions. The key strategic approach to carry out individual CGM research and development (R&D) projects was through partnerships, primarily with the GridApp™ Consortium utility members.

The scope of work for the Project involved three main tasks:

- 1) CGM Operations/GridApp™ Consortium
- 2) Technology Development Projects
- 3) Program Management.

2.0 DELIVERABLE / MAJOR MILESTONE STATUS

Description	Type	Baseline	Revised	Actual	Reason for Variance
1. Project Management Plan	D	02/28/06	12/01/06	12/01/06	Project initiation was delayed
2. Quarterly Reports	D	01/31/06 04/28/06 07/31/06 01/31/07 04/30/07 07/31/07 01/31/08 04/30/08		01/31/06 04/28/06 07/31/06 01/31/07 04/30/07 07/31/07 01/31/08 04/30/08	
3. Determine partnership projects with the GridApp™ Consortium	M	03/31/06	03/06/07	03/06/07	Extended with Cooperative Agreement Renewal
4. Make a go / no-go decision on partnership project(s) with the PSERC	M	01/31/06		01/09/06	
5. Deliver project development plans on partnership projects (University related Projects)	D	04/30/06		04/06/06 UIUC, 04/17/06 TAMU, 12/01/06 GIT	Georgia Tech submitted plan late
6. Conduct workshop on common data format and structure	M	05/31/06	Deleted		Deleted to avoid duplication of effort – see 06/19/06 Dan Markiewicz e-mail
7. Deliver workshop report (if the workshop is determined to be completed in the initial project prioritization)	D	07/31/06	Deleted		See Item 6.
8. Deliver project development plan for Technology Development Projects	D	06/31/06		08/17/06 DSFA 12/18/07 Wireless 07/13/07 AFAS (Phase 3) 10/31/07 Phasor	These plans were submitted as planning was completed

Deliverable / Major Milestone Status (Continued)

Description	Type	Baseline	Revised	Actual	Reason for Variance
9. Annual Reports	D	10/31/06 10/31/07		10/30/06 10/31/07	
10. Hold the public-day event for each University Related Project Technology Showcase	M	04/28/07		03/28/07 UIUC 04/13/07 GTI 04/24/07 TAMU	
11. Deliver two technology showcase reports, one for each technology	D	05/31/07		05/31/07	Sent as attachments to July'07 Quarterly Report
12. Final Report	D	06/29/07	06/30/08	06/30/08	Updated based on POP Extension
13. Revised PMP (Updated based on Cooperative Agreement Renewal)	D	12/01/06		12/01/06	
14. Complete identification of advanced technology projects (Updated based on Cooperative Agreement Renewal)	M	03/06/07		03/06/07	

3.0 SIGNIFICANT EVENTS AND ACCOMPLISHMENTS

The following table represents significant events and accomplishments covering the entire period of performance for the Center for Grid Modernization Program.

Date	Description
02/21/06	Held a project kickoff meeting with DOE
02/21/06	Awarded subcontract to Georgia Tech for a Distributed State Estimation demonstration system
02/28/06	Developed and submitted a Project Management Plan to DOE
03/02/06	Awarded subcontract to University of Illinois to integrate PSERC Control Center Visualization Techniques into the TVA-Hosted Southeast Wide Area Display Environment and to perform human factors assessment on these techniques
03/15/06	Awarded subcontract to Texas A&M to demonstrate improved Energy Management System applications during faults and restoration by using data from digital fault recorders, circuit breaker monitors, and digital protective relays
04/20/06	Placed modified subcontract with Georgia Tech with additional technical content - "Integration of PSERC Control Center Visualization Techniques into the TVA-Hosted Southeast Wide Area Display Environment".
04/27/06	Kickoff meeting at Texas A&M for their "Integration of Substation IED Information into EMS Functionality" project.
06/19/06	E-mail to DOE requesting that "Common Data Format and Structure" workshop/report be dropped from project scope.
08/09/06	Kicked off the internal CTC Distribution Fault Analysis System (DFAS) project
08/31/06	Held combined EI and CGM project status update meeting with Eric Lightner
09/18/06	Presented a paper covering the DFAS project at the IEEE-NAPS 2006 Conference in Carbondale, IL
09/30/06	Received a revision to the Cooperative Agreement with DOE, providing additional funding, and extending the POP through 03/30/08

Significant Events and Accomplishments (Continued)

Date	Description
10/31/06	Center for Grid Modernization Annual Status Report submitted to DOE
12/01/06	Revised Project Management Plan submitted to DOE
12/18/06	Distribution Wireless Communication Network project management plan completed
01/30/07	Center for Grid Modernization Quarterly Status Report submitted to DOE
03/13/07	Laurentiu Nastac presentation at CMU 3 rd Annual Conference on the Electricity Industry – <i>Advanced Fault Analysis System for Distribution Power Systems</i>
03/28/07	University of Illinois End of Project Demonstration Day at TVA
04/13/07	Georgia Institute of Technology End of Project Demonstration Day at Marcy Control (NYPA)
04/24/07	GridApp™ Consortium Board of Directors & Steering Committee Meeting
04/24/07	Texas A&M End of Project Presentation at GridApp™ Quarterly Meeting. Washington, DC
04/30/07	Center for Grid Modernization Quarterly Status Report submitted to DOE
05/08/07	University of Illinois Project Final Report
05/15/07	Georgia Institute of Technology Project Final Report
05/31/07	Texas A&M Project Final Report
05/31/07	Advanced Fault Analysis System (AFAS) Phase 2 Final Report
06/12/07	Laurentiu Nastac presented AFAS project at the EPRI Power Quality Applications (PQA)/Advanced Distribution Automation (ADA) 2007 Conference, Long Beach, CA, June 11-14, 2007
07/17/07	GridApp™ Consortium Board of Directors & Steering Committee Meeting
07/17/07	Idaho Power project - Advanced Capacitor Control (ACC) system demonstrated at GridApp™ Consortium meeting
07/31/07	Center for Grid Modernization Quarterly Status Report submitted to DOE
09/13/07	GenOnSys Phase I (Portland General Electric GridApp™ strategic project) – final report submitted
10/30/07	GridApp™ Consortium Board of Directors & Steering Committee Meeting, Morristown, NJ
10/31/07	Center for Grid Modernization Annual Status Report submitted to DOE
10/31/07	Project management plans submitted for: <ul style="list-style-type: none"> - Advanced Distributed Energy Storage (First Energy GridApp™ core project) - Coordinated Control (DTE Energy GridApp™ core project) - Substation Engineering Modeling Tool (SCE GridApp™ core project) - GenOnSys Phase II (PGE GridApp™ sponsor project) - GridSense LineTracker™ DataPAC Development (CTC / SCE / DTE Energy / Exelon GridApp™ sponsor project) - Phasor Measurements (CTC technology development project)
01/04/08	Contract documentation in place for: <ul style="list-style-type: none"> - SCE's GridApp™ core project - DTE Energy's GridApp™ core project - FirstEnergy's GridApp™ core project - Georgia Tech's technology development project

Significant Events and Accomplishments (Continued)

Date	Description
01/31/08	Center for Grid Modernization Quarterly Status Report submitted to DOE
02/14-15/08	GridApp™ Consortium Board of Directors & Steering Committee Meeting, San Diego, CA
02/20/08	Received no-cost, 3-month POP extension from DOE
02/25/08	Provided a presentation to key DOE participants in Washington, D.C. to discuss the continuation of the GridApp™ Consortium
04/21/08	GridApp™ Consortium project review meeting in conjunction with the IEEE PES T&D Conference, Chicago, IL, including project presentations and demonstrations for: <ul style="list-style-type: none"> - Distribution Wireless Communication Network - PGE GenOnSys II - Exelon Radio Communicating Fault Indicators - DTE Energy Coordinated Control - SCE Substation Engineering Modeling Tool
04/30/08	Center for Grid Modernization Quarterly Status Report submitted to DOE
04/30/08	Project completed and final report submitted for: <ul style="list-style-type: none"> - Southern Company Phasor Measurement Business Case Analysis (<i>CTC</i> technology development project)
05/05-06/08	Integrated State Estimation Project for the Virgin Island Water and Power Authority (<i>CTC</i> technology development project) – Technical demonstration at VIWAPA, St. Thomas, USVI
06/30/08	Project management plan submitted for: <ul style="list-style-type: none"> - Radio Communicating Fault Indicators (Exelon GridApp™ strategic project)
06/30/08	Projects completed and final reports submitted for: <ul style="list-style-type: none"> - Advanced Distributed Energy Storage (FirstEnergy GridApp™ core project) - Coordinated Control (DTE Energy GridApp™ core project) - Substation Engineering Modeling Tool (SCE GridApp™ core project) - Advanced Capacitor Control System (<i>CTC</i> / Idaho Power / FirstEnergy GridApp™ sponsor project) - GenOnSys Phase II (PGE GridApp™ sponsor project) - GridSense LineTracker™ DataPAC Development (<i>CTC</i> / SCE / DTE Energy / Exelon GridApp™ sponsor project) - Radio Communicating Fault Indicators (Exelon GridApp™ sponsor project) - S&C TripSaver™ Development (DTE Energy sponsor project) - Advanced Fault Analysis Software System (<i>CTC</i> technology development project) - Distribution Wireless Communication Network (<i>CTC</i> technology development project) - Integrated State Estimation Project for VIWAPA (<i>CTC</i> technology development project)
06/30/08	Project completed and final report to be submitted under separate cover: <ul style="list-style-type: none"> - Integrated State Estimation Project for VIWAPA (<i>CTC</i> Technology development project)

4.0 PROGRAM ACCOMPLISHMENTS

This Final Report satisfies the last deliverable of the Center for Grid Modernization Program. The report provides an overview of the activities and accomplishments of the program throughout the period of performance.

The primary objectives of CGM were to contribute to the modernization of the nation's electricity transmission and distribution infrastructure; to enhance the security, reliability and quality of electricity delivery by organizing, coordinating, and leveraging resources of utility industry, universities, and government; and to select and execute short-term, high-priority R&D projects in a partnering environment. The program included a focus on the continued operation of the GridApp™ Consortium and continued involvement of key stakeholders who participate in planning, selecting, developing and/or demonstrating advanced technology development projects. Within the funding and scheduling limitations of the Program, CTC engaged DOE, utilities, industry, universities and major consortia to identify stakeholders interested in collaborating on high-impact projects that strive for the DOE national vision of "Grid 2030".

The innate value of the CGM program is in the execution of technical projects. These projects support the development and pilot-demonstration of technologies to furnish real-time or near real-time information to both utilities and electricity consumers. Utilities use this information to plan, monitor, analyze and manage grid operations for enhanced reliability of electricity delivery. Electricity consumers can use the information to make decisions on participation in demand management and load control practices, based on market pricing and other economic incentives. Thus, CGM efforts focused on development of new and advanced sensor/communication/information/control technologies and their integration into grid infrastructure, from generation down to end use. These technologies enable delivery of timely information for decision making by both utilities and consumers.

The following report sections provide discussions of the progress made through the GridApp™ Consortium, CTC-managed Advanced Technology Projects and Program Management of CGM.

4.1 CGM Operations / GridApp™ Consortium

Within the CGM development and operations, CTC prepared the necessary procedures and tools to perform CGM functions. This included developing an "identity" for the CGM including a mission, vision and logo. Methods to solicit and evaluate potential projects were documented and communicated to organizations involved with the CGM. Monitoring and management of the technical projects was also addressed.

The GridApp™ Consortium mission is to utilize a core set of electric industry stakeholders to identify and apply best utility technologies and practices to modernize electric transmission and distribution operations. The GridApp™ vision, as defined by GridApp™ Consortium members, is to be the premier organization utilized by electric

industry stakeholders for the demonstration, validation, integration and transfer of new grid-related technologies into commercialization for broad industry deployment.

CTC served as the organizer of the GridApp™ Consortium, providing management support to continue the consortium operation including the Board of Directors, the Steering Committee and various Project Working Groups. *CTC* managed the project development, execution and tech transfer of the GridApp™ projects. The GridApp™ name, logo and external website were maintained and trademarked.

Within the Center for Grid Modernization Program, *CTC* continued the following tasks:

- Consortium Management
- Project Development, Execution, and Tech Transfer
- Database and Website Management.

4.1.1 GridApp™ Consortium Management

CTC management activities included interpreting/maintaining the By-Laws for the consortium, organizing periodic consortium management meetings, recruiting other interested utilities to become members and implementing the process to identify beneficial near-term technology projects.

CTC provided an active role in the project and proposal development for the consortium members. This included management support for informational and accurate project plans to be used throughout the project process.

CTC participated in industry organizations, seminars, conventions and other consortium activities. This activity included meetings of the North American SynchroPhasor Initiative (NASPI), industry events like DistribuTECH, and coordination meetings with other consortia like the National Electric Energy Testing Research and Applications Center (NEETRAC) and the Power Systems Engineering Research Center (PSERC). Involvement with these agencies assisted in transitioning university-based R&D projects through the GridApp™ Consortium for eventual commercialization and adoption by the industry.

The GridApp™ Consortium held quarterly meetings that were supported by the host utilities at the member's site. *CTC* continued the GridApp™ management including meeting planning, organizational logistics, facilitating, and reporting. This also included meeting location, arrangements, logistics, allocation of labor and non-labor resources required to facilitate meetings, development of meeting agendas, and invitation and attendee confirmation. *CTC* compiled meeting minutes and updated action items to maintain information flow.

CTC was also tasked with developing the plan to continue the GridApp™ Consortium into the future. *CTC* prepared GridApp™ follow-on white papers and made presentations to the DOE for future activities. The presentations are itemized in Section 3.0, Significant Events and Accomplishments.

4.1.2 Project Development, Execution and Tech Transfer

CTC supported the engineering development, demonstration and validation of selected high-impact technologies to also include the transition of best technologies and best practices into broader use by member utilities. Stakeholder benefits included development and deployment of grid modernization technologies that individual utilities did not have or could not undertake without the benefits of the cooperation under the GridApp™ Consortium. *CTC* provided best technologies and practices with a viable market size for commercialization success, while providing a collective voice of the utility industry on the importance of technology investments.

Project identification and development for the GridApp™ Consortium came from various means.

- Consortium Members – Consortium members assessed near-term, high-impact, widely applicable technology projects. These projects met specific criteria and were approved by fellow members.
- Technology Gap Analysis – A technology gap analysis had been previously performed and helped identify project opportunities not covered by consortium member projects.
- Other Utility/Vendor/University Partnerships – Through efforts conducted under this program, other contacts were made and project opportunities were identified.
- Technology Database – Technologies were identified as commercial off-the-shelf (COTS), near-COTS, in development, or R&D. Those technologies identified as near-COTS were further investigated as appropriate.

A project selection process was developed and was utilized for project transition. All projects that were selected through the previously named means met all specific evaluation criteria including technical merit, technical approach, project management, and implementation potential. The strengths and weaknesses of each category were identified by the reviewer, and an overall score was accumulated. This ranking method allowed for a democratic review of the projects selected.

Any demonstration/validation of select technologies was conducted either at the technology vendor/utility facilities, *CTC*'s Johnstown, PA facility or both, depending on individual technologies and the levels of collaboration established between *CTC* and individual technology providers/utilities.

CTC provided technical evaluation for projects within the GridApp™ Consortium. The *CTC* level of effort was different for each project varying with each project's technical aspects and needs.

The following Core Projects, performed by Charter Members, and Sponsor Projects, performed by Sponsor Members, were undertaken by the GridApp™ Consortium.

4.1.2.1 Core Project – Advanced Distributed Energy Storage – FirstEnergy

Problem / Need

Energy storage systems can be used to follow load, stabilize voltage and frequency, manage peak loads, improve power quality, defer upgrade investments and support renewable energy resources. However, the integration, communications and control related to broad deployment of energy storage as a valued system asset remains a technological challenge. Several factors have set the stage for the testing of energy storage in the distribution system including constraints on the network, aging infrastructure, concerns about reliability and power quality, as well as the readiness of energy storage technologies.

Goals and Objectives

The primary goal of this project was to integrate and test the application of a Premium Power zinc-flow battery that is installed, controlled and functionally operated in an electric distribution system.

The objectives of this project included the following:

- Evaluate the energy storage system through integration into the utility distribution system, including validating energy storage density and deep discharge capability
- Evaluate energy storage system modularity and scalability on a comparable utility application for making the system architecture flexible and easy to install and maintain
- Document and report interim test results, including performance, operation and reliability of the energy storage system, as well as the engineering, procurement, installation, integration and operating cost of the system
- Document and report final results including potential utility system benefits and steps necessary for broad utility deployment of the technologies
- Develop specification requirements for the utility application based on operation and results
- Host a site visit to demonstrate the energy storage system integration.

Accomplishments

FirstEnergy was the first utility to purchase and test Premium Power, Inc.'s PowerBlock 150 System as a complete energy management solution. All other installations have been telecommunications applications. It is a Zinc-Flow energy storage double-conversion in-line device. This GridApp™ project was proposed to extend an EPRI project and provided for additional testing, validation and development of the PowerBlock 150 for utility applications. This zinc-flow battery R&D project tested how the unit could be installed, interconnected, operated and maintained in a distribution system in order to validate the technology and bring the technology closer to broad deployment for utility applications.

The system is comprised of three components, the PowerBlock, a 7.5 ton chiller for heat management and an automatic transfer switch. Figure 1 is a schematic configuration of the three components.

Figure 1 – PowerBlock System Components

The PowerBlock 150 System was interconnected with the Jersey Central Power & Light / FirstEnergy distribution system in December 2006. It was commissioned, and a series of tests were performed. The PowerBlock system was installed “behind the meter” to support a 480 VAC service to test the value proposition hypothesis for each of three potential stakeholders—the local electric distribution company, the load served and the Independent System Operator.

The PowerBlock was designed for a UPS application—to operate infrequently and at full capacity. This test and utility application development work demonstrated that the PowerBlock could perform a daily charge/discharge cycle. The testing provided direction regarding the design changes that will be required for robust operation in a utility environment. At the same time this evaluation provided an understanding of which parts of the system were over-designed for the utility application.

Experience and understanding of the performance was gained from activities including installation, integration, interconnection, operation and functionality enhancement through software/firmware development. The operation of the energy storage system provided peak load relief, operational flexibility and back-up power during emergency contingencies to the benefit of the local distribution utility.

4.1.2.2 Core Project – Coordinated Control – DTE Energy

Problem / Need

On a typical distribution circuit, devices that control the voltage and power flow are locally and individually controlled. Care is taken during the design phase to establish optimal set points for the individual devices, but these set points are often based on peak load conditions. Major changes in circuit topology can significantly alter the effectiveness of the original design and set points. Often with local controls, problems arise due to oscillations, and the controls must be detuned to prevent such events.

Most of the time, minimizing circuit losses while maintaining voltage criteria is a sufficient objective for a control algorithm. At times a distribution circuit can be so heavily loaded that losses will take a back seat to transformer or cable capacity limits. During these “capacity constrained” hours, the controller should maximize capacity instead of minimizing losses.

Many research efforts are dedicated to developing “smart” devices that offer flexible operation and control options; however, a utility cannot simply discard and replace the existing infrastructure overnight. A practical controller must work with both locally and remotely controlled devices to allow a utility to incrementally implement its grid modernization strategies.

To further assist utilities in modernizing, technologies are emerging to give legacy equipment some of the capabilities of their “smart” counterparts at a fraction of the cost of replacing the equipment. These technologies often lack common control and communication standards across manufacturers.

Goals and Objectives

The objectives of this project included the following:

- Develop a model-based, hierarchal control scheme that automatically aligns the model with the physical system via an XML measurement interface
- Coordinate all active control devices to provide more efficient and reliable operation
- Develop a fault location algorithm that can assist the controller in recognizing unscheduled topology changes
- Retrofit existing legacy equipment to improve capabilities without costly device replacement
- Integrate “smart” equipment with retrofitted legacy equipment and locally controlled “dumb” devices to provide an incremental path for distribution system modernization
- Develop a communication application to interface monitoring and control equipment with various types of communication methods and protocols.

Accomplishments

Legacy capacitors, voltage regulators and reclosers were successfully retrofitted with control and communication equipment. Although communication with the devices proved challenging, the DNP Master application developed by DTE Energy has successfully collected data from all devices.

Two sets of GridSense LineTracker™ devices were installed on the circuit. These devices provide data to a fault location algorithm developed by Electrical Distribution Design (EDD). The algorithm determines probable fault locations and can be used to automatically notify planning and operation personnel. The algorithm can be used for momentary and full forced outages.

The collected data along with outage data and fault records from the LineTrackers™ is available to the Coordinated Controller via an XML interface. The Coordinated Controller, developed by EDD using the DEW environment, is successfully retrieving data and validating the accuracy of the model.

The Coordinated Controller has an offline study mode that compares the normal control of the active devices to coordinated control. Study mode can help analyze the benefits of coordinated control, identify potential circuits for automation projects and help tune the real-time control parameters. Early study mode analysis indicates significant cost savings for coordinated control.

4.1.2.3 Core Project – Substation Engineering Modeling Tool (SEMT) – Southern California Edison

Problem / Need

Modernizing the electric power system to improve reliability is an unending process. Engineering, designing and building new substations and upgrading existing substations with modern intelligent electronic devices (IEDs) requires significant man-hours. As utilities deal with increasing costs and attrition of their experienced technical workforce, new tools are needed to decrease these man-hours. An additional need is to improve the accuracy of the design to reduce errors and omissions.

Goals and Objectives

Develop a software tool that decreases the man-hours required for the engineering and designing of substations with IEDs from multiple vendors and increases the accuracy of the design.

Accomplishments

Southern California Edison (SCE) had previously built a substation modeling tool that was specific to one IED vendor. This project built a new tool that can be used with the latest SCE design for substation monitoring and control with multiple IED vendors. The new SEMT supports the IEC 61850 standard for the design of substation automation. .

GridApp™ members and invited guests had the opportunity to participate in monthly working group teleconferences and witness a demonstration of the SEMT tool. SCE deployed the SEMT tool, and it is now being used for production projects.

4.1.2.4 Sponsor Project – Advanced Capacitor Control System (ACCS) – CTC, Idaho Power, FirstEnergy

Problem / Need

Idaho Power's Automated Capacitor Controller System (ACCS) can help solve many long standing problems for the electric utility industry. Distribution capacitors for voltage support and reactive power contribution are a necessary part of the utility electrical system. Controlling these capacitors in a manner that is effective from both a local and system perspective has long been a challenge. Controlling reactive power flow using the ACCS can significantly enhance performance of the distribution system by reducing losses and improving the voltage profile on the distribution feeders. This in turn reduces the loading and losses on the substation transformer and the associated transmission system. The change in losses throughout the total electrical system is significant.

Reactive requirements of embedded distribution systems may limit large power transfers across electrical transmission systems. Coordinated control of capacitors within distribution systems can be harnessed for the benefit of the transmission system without

harming the operation of the distribution system. This enhancement supports the transfer capability of the transmission system.

Hundreds of man-hours could be saved annually by avoiding unnecessary distribution capacitor reviews to determine where and what size capacitor banks should be utilized. Diagnostic verification of distribution capacitors for blown fuses, failed capacitor packs or other irregular problems is a real need. These diagnostics can help ensure the reliability of the reactive compensation of a system when it is most needed.

Idaho Power's ACCS allows new capacitors to be quickly added to a distribution system as capacitor needs change. It allows capacitors to be controlled independently for the benefit of the entire distribution system. Capacitor status and operation can be monitored and reports generated for all control system operations. The ACCS provides the capability for automatic periodic tests of capacitors to verify their operational integrity. The expanded use of this system has the potential to significantly improve the voltage profile for individual feeders, increase energy transfer capability, reduce system losses and enhance distribution system performance.

Goals and Objectives

The goals and objectives for this project are listed below.

- Enable utilities to modernize and automate capacitor control
- Institutionalize the control and reporting of reactive power management and devices on the grid
- Modernize the ACCS controller with a ruggedized PC and make it compatible with today's Microsoft Windows operating system
- Obtain third-party support for future ACCS installations
- Provide multiple wireless communication platforms for capacitor control
- Deploy a prototype ACCS on one of Idaho Power's distribution circuits utilizing VHF communications
- Deploy a second prototype ACCS on a FirstEnergy distribution circuit utilizing cellular communications to control multiple distribution capacitor stations
- Inform and educate other utilities on the use of this technology, through the GripApp™ Consortium.

Accomplishments

Idaho Power, FirstEnergy, CTC and Schweitzer Engineering Laboratories, Inc. (SEL) partnered on this project to further the development and commercialization of Idaho Power's ACCS. The initial intent of this project was for Idaho Power to guide FirstEnergy on the installation, commissioning and training for the ACCS. However, while seeking to update the ACCS computing platform for long-term viability in a utility atmosphere, the project team decided that upgrades to the system's equipment were needed to make it more durable, up-to-date and flexible. They found that upgrades to the original software, integrated into SEL's SEL3351 Substation Computer would satisfy all the project's needs. In a win-win collaborative effort, all of Idaho Power's original ACCS software code was translated to the newest Windows platform and integrated into

the SEL3351 system, with the goal of offering the ACCS as a commercial option upon successful completion of the project.

Idaho Power purchased a prototype SEL3351 with the ACCS option for testing at one of their substations to resolve any issues and ensure the system functioned as required. Idaho Power chose their WYEE substation as their demonstration site. The WYEE substation has three transformers (one 37.3 MVA and two 30 MVA) and 10 distribution circuits. This substation had an existing Idaho Power ACCS installed, which supported the validation of the new SEL3351 ACCS with the available historical data. Idaho Power received their prototype SEL3351 ACCS in late February 2007 and installed the system shortly thereafter using their existing radio communication system and capacitor controller. When the ACCS was energized and the appropriate capacitor bank information was entered, the system immediately began operating capacitor banks to regulate the system volt-ampere (VAR) requirement as planned. Figure 2 illustrates Idaho Power's ACCS installation.

Figure 2 – Idaho Power WYEE Substation ACCS Equipment Diagram

FirstEnergy selected their Kenvil substation, located about 15 miles northwest of Morristown, for their pilot site. The Kenvil Substation has 24 capacitor banks installed on four distribution feeders (six of the 24 capacitor banks are fixed). FirstEnergy decided to install 18 new FP4500 Fisher Pierce capacitor control systems, modified to accept a Sierra Wireless AirLink modem utilizing Nextel cellular communications, on the remaining switchable capacitor banks with the fully deployed ACCS. FirstEnergy continues to work with Idaho Power, SEL and Joslyn Hi-Voltage to resolve communication issues found between the AirLink modem and the FP4500 controller. FirstEnergy is making progress and is confident that the cellular communication style can be made functional. They feel the concept of the ACCS is worthwhile and will continue

to direct corporate funding to this project until it is successful. Figure 3 illustrates FirstEnergy's ACCS installation.

Figure 3 – FirstEnergy Kenvil ACCS Equipment Diagram

SEL's involvement in the GridApp™ ACCS project has allowed Idaho Power's in-house ACCS product to be enhanced and expanded to become a commercially-available product. Electric utilities will soon have the ability to purchase the ACCS option along with the SEL3351 computing platform, with no licensing fee for FY2006 GridApp™ members, greatly expanding the platform's potential customer base. The addition of industry-standard, up-to-date operating system support and communication options as a result of this project provide even more value to the ACCS. The ACCS design also benefited from field testing, operating performance data and feedback provided by the GridApp™ project participants. This product will reach the market with even more value and stability as a result.

4.1.2.5 Sponsor Project – GenOnSys Phase II – Portland General Electric

Problem / Need

Distributed generation throughout the nation is being developed using large scale wind turbines, biomass, geothermal, small hydro and other renewable and non-renewable resources. Ultimately, such distributed resources may be aggregated and operated as a single or several "virtual power plants", fully integrated in "smart grid" system operations with a combined capacity of hundreds of megawatts. Telemetry will play a vital role in integrating this distributed generation, thereby enhancing the capability of the electric system. Utilities currently require different levels of telemetry for these facilities, but the high costs can be a significant barrier for smaller scale systems.

Also, there is much interest in increasing development of these renewable distributed energy resources (DER) by consumers, utilities and utility regulators. To date, a

universal standard system for the integration of DER into utility system control centers (SCC) and independent system operators (ISO) has not been established. Several ISOs have tried to establish some form of reporting generator status and verification of operation, but there has yet to be a generally accepted standard.

GenOnSys, Portland General Electric's DER control system, has been in use for five years with continual process improvement for the data collection and reporting to PGE's system control system and supervisory control and data acquisition (SCADA) system. Although a proven system for remote generator operations, GenOnSys lacks several features to make it a powerful tool for universal application:

1. A standardized interface/protocol for linking to any ISO or utility system control center
2. A standardized naming convention and data structure simplifying the application for all forms of DER
3. A uniform set of graphics to make it easy for any user to develop custom screens for the DER sites.

Goals and Objectives

The primary goal of Phase II was to develop the easiest path for integrating DER into the electric power system via a SCC or ISO. Phase II will integrate GenOnSys into an electric power system—SCC, ISO or Regional Transmission Organization (RTO). Research will be conducted into the data formats for presentation to SCCs, ISOs and RTOs and the best protocols to use for both hardware and software.

This project will build an interface with GenOnSys that would utilize the Intercontrol Center Communications Protocol (ICCP). ICCP is an international standard (IEC60870-6 TASE.2) to enable integration of real-time data between control centers of different utilities over a wide area network.

In addition, research would be conducted with a number of SCCs, ISOs and RTOs, such as with Bonneville Power Administration, PacifiCorp, Idaho Power, Power Utility Districts, California ISO, Midwest ISO and others. Through the research, a standard will be determined for identifying the DER facility, feeder location, substation, time-stamp, megawatts, megaVARs, etc.

Accomplishments

PGE built a set of master object templates that represent a remote DER site and its associated equipment as a set of predefined IEC-61850 CDC classes constructed in a parent child hierarchal view. This has allowed them to develop a standard Generator template for a generator site, which is used to create a new instance of the template when a new site is designed.

The key accomplishments of this project are as follows:

- Successfully deployed the ICCP communications and read data points from four (4) different sub-stations. This communication link will enable PGE to develop relationships with other SCCs, RTOs and ISOs by executing real-time event bi-directional data securely between systems and import or export control, feeder megawatt loads, Volts, Amps, and type data with the GenOnSys DER system.
- Demonstrated the ability to dispatch a generator over long distances using the IEC-61850 Standard and process automation objects in a distributed system dispersed over a large geographical area.
- Proved that viability of an open architecture and object base system running on Microsoft platforms can be successfully integrated with Unix SCADA platforms using ICCP and current technology.
- Demonstrated the successful implementation that IEC-61850 can be used for DER Operations. Originally the standard positioned itself for UCA and substation IEDs.
- Demonstrated remote service management by using VPNs and Terminal Services. This allowed both PGE remote sites and other sites to be managed in a secure manner.
- Finally, a successful demonstration was completed of this new GenOnSys Version 2.0 incorporating GridApp™ Phase I and Phase II work by demonstrating the ICCP link and starting a distributed generator remotely from Chicago during the GridApp™ meeting of members, prospective members, DOE representatives and some vendors on April 21, 2008.

4.1.2.6 Sponsor Project – GridSense LineTracker™ DataPAC Development – CTC, Southern California Edison, DTE Energy, Exelon

Problem / Need

The LineTracker™ manufactured by GridSense Systems, Inc., is a circuit monitoring device that is used by many utilities to capture critical operational and non-operational data points including line load, fault currents, fault waveforms, interruption, outage and restoration records on distribution circuits. The data from the LineTracker™ is communicated to a local data concentrator via low power radio and then transmitted to a central location using point to point cellular technology. A new backhaul communication system was required so utilities could access the data in a utility friendly format with a more reliable long distance communications link. Figure 4 shows a GridSense LineTracker™ device.

Figure 4 – GridSense LineTracker™

Goals and Objectives

The objective of this project was to develop a pole attached data concentrator (DataPAC) that uses the utility standard Distributed Network Protocol 3 (DNP3) protocol with cellular and CellNet mesh network radio communication. The DataPAC would act as an intelligent data node, enabling utilities to have direct and seamless integration of LineTracker™ data to existing SCADA systems and other third-party systems.

Accomplishments

CTC, SCE, Exelon and DTE Energy worked with GridSense to define the functional and operational requirements for the new DataPAC. Based on these requirements, GridSense performed the following work.

- Four DataPAC proof-of-concept prototypes with DNP3 and CellNet were manufactured. Two of these were shipped to GridApp™ utility sites for evaluation. One was installed in a local accessible test site for continuous operation. The final prototype remains with the GridSense engineering team as a platform for testing and further development.
- The DataPAC was developed in multiple phases with two goals in mind—first, to develop a robust enhanced device that provides data collation for the LineTracker™ sensors, and second, to include DNP3 support and operation with the Cellnet wireless radios. Upon reaching the first goal, GridSense installed a test site locally that consisted of three LineTracker™ sensors. The test site utilized circuit switched cellular modem technology. The test site was continually monitored over a two-month period, with over 50 remote data transfers occurring.
- To validate the second goal, GridSense engineers utilized the Triangle Microworks Protocol Test harness. The testing was conducted in the GridSense office with multiple LineTracker™ sensors operating on an in-house test fixture. Simulations of real-world events were generated, and both DNP3 Polled mode and unsolicited operation were validated.

It was necessary to move the field testing from DTE Energy to Exelon because of schedule restrictions on integration of the DataPAC with cellular communications. Southern California Edison and Exelon have deployed the new systems and are continuing to work with GridSense. The development of the new DataPAC enables the LineTracker™ devices to be an integrated data node for the smart grid.

GridApp™ members and invited guests had the opportunity to participate in a demonstration of the LineTracker™ and the new DataPAC.

4.1.2.7 Sponsor Project – Radio Communicating Fault Indicators – Exelon

Problem / Need

Faulted circuit indicators (FCIs) have become an important tool for utilities to reduce customer outage times and improve their Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Duration Index (SAIDI) performance. These FCIs are designed to provide visual indication that a fault has occurred downstream from the devices. FCIs can reduce the time and cost required to locate a fault on the distribution system.

Remote reporting FCIs allow the utility workers to begin troubleshooting an outage without driving to the FCI location. While actual CAIDI improvement measurements are outside the scope of this project, it is generally accepted that eliminating the travel time for data retrieval can reduce an outage's duration by 10 to 30 (or more) minutes depending on geography and traffic congestion.

Overhead fault indicators with remote reporting are available on the market. However, existing products require additional equipment to collect the fault indicator status and to relay the data to utility operators using one of several after-market wireless methods.

Goals and Objectives

The primary goal of this project was to modify a commercial FCI so that it could report its status through an existing automatic meter reading (AMR) radio network. Project objectives included the following:

- Integrate a state-of-the-art Cellnet UtiliNet 900 MHz AMR radio inside an overhead FCI and leverage an existing UtiliNet mesh network for communication. The final product will be a self-powered, stand-alone device that does not require any additional pole mounted equipment at the site.
- Install, test and operate the FCI system on an electric distribution system.
- Develop a software transition for FCI data integration into the SCADA system. The project is expected to provide utilities with an immediate, easily deployable and cost-effective solution for real-time monitoring of fault occurrences.
- Focus on assuring commercialization of the product through integration partner participation and collaboration with SEL.

Accomplishments

This project demonstrated the incorporation of state-of-the-art radio technology directly into an FCI. The self-powered device was installed on an overhead distribution circuit with a grip-all stick. No external power source or other cabinets are required at the FCI location.

SEL developed a new overhead FCI that incorporates a two-way UtiliNet radio (operating on a 900 MHz mesh-radio system developed by Cellnet Technologies). Exelon obtained the new FCIs from SEL and installed them on ComEd distribution circuits in an area already served by a UtiliNet AMR radio network. Then Exelon created a streamlined head-end process to ultimately get FCI data into SCADA (PI) Historian with minimal intervention. Figure 5 is a preliminary model of the device that was used in the field trial.

Exelon created a back-end system to receive and process FCI “report by exception” transmissions. This work addressed the following issues and questions.

- How FCI data will be stored.
- If an FCI will be queried during a feeder lockout. The result was that the FCIs are not queried. They report by exception, but do not accept incoming radio traffic. This was done to conserve battery life.
- Creation of a user interface for trouble crews with mobile communications and computing (field crews with a laptop computer and Internet connection). The Intranet web based interface allows the user to report on FCIs by office and/or feeder. Users can also look up historical readings by FCI and obtain driving directions to the location via MapQuest.

Exelon worked with its vendors to identify and resolve communication issues between the FCI and repeater radio devices. Exelon also investigated various areas of FCI control logic. Some design decisions included:

- How often should the FCI report in? Decision – periodic reports occur once every eight hours.
- Should the unit provide a report by exception upon loss of voltage whether or not the device saw fault current? Decision – when power is lost for more than two-minutes, the FCI sends a “report by exception” message that includes the target status, loss of current, loss of voltage, or both. If power is restored within the first two minutes, the FCI logs the event in its memory and adds the information to the next periodic update.

Figure 5 – Preliminary FCI Model

- Should the FCI report upon restoration of voltage? Decision – no report is issued when power is restored.
- What other parameters should be reported? Decision – reporting parameters include fault threshold setting, battery strength, radio discovery time, number of events with loss of voltage, current or both, since the last report and in the FCI's lifetime.

Exelon prepared a detailed report describing the integration of the new FCIs on the Exelon (ComEd) distribution system. The report included a description of the field demonstration.

Exelon hosted a showcase demonstration of the FCI technology in conjunction with the IEEE Power Engineering Society meeting in Chicago, IL on April 21, 2008. Using a VPN connection to the Exelon corporate server, Exelon conducted a live demo of their FCI web-based reporting tools.

4.1.2.8 Sponsor Project – S&C TripSaver™ Development – DTE Energy

Problem / Need

Temporary faults on overhead distribution circuits are a growing problem for electric utilities, with over 90% of momentary outages occurring on circuit laterals. These faults translate into lost revenue, as crews must be dispatched to find and replace the blown fuse or switch a substation breaker back on. A method of diminishing momentary outages for customers is needed, directly increasing customer satisfaction.

Through the GridApp™ Consortium, DTE Energy and the S&C Electric Company teamed up on this pilot project to test and install the new S&C TripSaver™ Dropout Recloser, with hopes of finding a new tool that can relieve some of the traditional reliability issues that have hindered utilities and their customers in the past. The purpose of this study was to assist in the commercialization of the S&C TripSaver™ Dropout Recloser. It is anticipated that the TripSaver™ will have a significant impact on the reliability of distribution systems in the future.

Goals and Objectives

The goal of this project was to demonstrate that the S&C TripSaver™ Dropout Recloser system is a product that will help decrease the frequency of overhead lateral momentary outages. Specific objectives include the following:

- Receive a quantity of TripSaver™ products from S&C for test and evaluation
- Test a sample of the unit(s) at an independent utility high current laboratory
- Locate distribution lines suitable for TripSaver™ evaluation, researching areas with a high instance of temporary faults
- Devise proper training and technical standards for installation and maintenance of the TripSaver™ Dropout Recloser

- Install beta versions of the TripSaver™ Dropout Recloser in previously selected sites and monitor them for a period of four to six months
- Analyze the outcome of the test results at the S&C Electric Company test facility with experts from S&C engineering, DTE Energy, CTC and other GridApp™ members as necessary
- Determine the anticipated reliability and possibilities for commercialization of the product
- Aid in the development of a commercialized product that is suitable for purchase off the shelf and included training and technical standards completion
- Inform and educate other utilities on the use of this technology, through the GridApp™ Consortium.

The following overall benefits will be realized from this project:

- Improved SAIDI without sacrificing Momentary Average Interruption Frequency Index (MAIFI) for utilities using a fuse-blowing approach
- Improved MAIFI without sacrificing System Average Interruption Frequency Index (SAIFI) for utilities using a fuse-saving approach
- Reduced number and duration of utility crew callouts
- Increased customer satisfaction through the reduction of temporary and/or permanent outages
- Expedited deployment of technology.

Accomplishments

The S&C TripSaver™ Dropout Recloser is a single-phase operating device that features an open-close-open-dropout operating sequence with a 5-second reclosing time interval. The interrupter, internal to the S&C TripSaver™ Dropout Recloser, resets five seconds after dropout and then is ready for the next sequence. The purpose of using S&C TripSaver™ Dropout Reclosers on the electrical distribution system is to save from “fuse blowing” during temporary fault incidents. Studies show that more than 90% of faults on laterals are momentary faults. It is expected that the TripSaver™ units will provide ideal protection on distribution laterals that experience frequent momentary faults.

The DTE Energy Power Laboratory, with support from CTC, performed electrical testing during this project. The physical testing and handling analysis was completed at the DTE Energy Overhead Lines Center of Excellence by experienced DTE Energy overhead linemen with the assistance of the International Brotherhood of Electrical Workers (IBEW) Local 17 union safety director. These parties worked together and provided valuable feedback that led to design modifications of the TripSaver™ units by S&C. Figure 6 illustrates the TripSaver™ in a ceramic cutout at the DTE Energy training facility.

Figure 6 – Physical Testing at DTE Energy Facility

Once the S&C TripSaver™ Dropout Recloser was validated both electrically and physically, DTE Energy installed six TripSaver™ Dropout Reclosers on two distribution circuits. These distribution circuits have miles of single-phase lateral distribution lines passing through rural, heavily forested areas. Each of the TripSaver™ locations were monitored remotely, using GridSense LineTrackers™ and cellular communication technologies to document and validate the field application. In addition to lab testing and field verification of the S&C TripSaver™ Dropout Recloser, DTE Energy provided insight into nomenclature, training and technical standards.

Moving forward, DTE Energy will maintain the field trial TripSaver™ devices throughout 2008. Following the field trial, if the TripSaver™ continues satisfactory operation, they will be replaced with new TripSaver™ devices to continue providing improved customer service. Upon removal, the tested TripSaver™ devices will be returned to S&C for evaluation.

4.1.3 Database and Website Management

The GridApp™ website (<https://www.gridapp.org/>) was maintained with the most current member and project information. The website contained key information including a database of near-term grid modernization technologies, priority list of high-impact grid modernization technology areas, GridApp™ members and their respective projects and information from GridApp™ sponsored meetings. CTC provided technical oversight and final content approval to ensure technical integrity of the website.

CTC maintained a projects and meeting list that informed all viewers of unrestricted GridApp™ activities. CTC maintained the members-only project resources and meeting minute informational forums on the website for the project working groups to support information dissemination.

4.2 Advanced Technology Projects

This task focused on the execution of several advanced technology projects. These projects were developed and selected from several sources, including GridApp™ Consortium charter and sponsor members, other electrical utility organizations, electrical equipment/systems suppliers and universities. In all cases these projects were selected with emphasis on the following goals:

- High impact technologies that could make tangible contributions through short-duration projects
- Enabled progress toward Grid 2030 visions of improved grid efficiency, operation and maintainability
- Involved the effective acquisition, communication, processing and utilization of real-time grid data
- Took advantage of organizations and consortiums to maximize the benefits of developed and applied solutions.

Where appropriate, partnering projects were formed so that the resulting outcome extended beyond what any one organization could achieve alone. *CTC* reached out to major consortia with specific interest in grid modernization for partnerships to support the CGM operations. Potential consortia targeted for establishing partnerships with the CGM included the GridApp™ and the PSERC consortia. Discussions with several other organizations such as NASPI and NEETRAC were also pursued for coordination of activities.

Projects were developed and executed within the limits of scope, budget and schedule available through the CGM program. The technical tasking of these projects was performed by a variety of qualified organizations including utilities, universities, *CTC* and electrical utility equipment/service providers. In each case, the projects were selected and executed in such a fashion to assure optimum utility industry involvement and technology transfer aimed toward extensive utilization. Project proposals were solicited from interested organizations and evaluated by the CGM. These projects were typically developed as team efforts, with required cost-sharing.

Three projects were selected and funded early in the program, based on collaboration with PSERC. *CTC*'s participation with these projects was in the form of technical management and coordination of research projects and selection of research project(s) for further engineering development.

- Distributed State Estimation and Alarm Processing, performed by Georgia Institute of Technology – The goal of this project was to develop a prototype distributed state estimator (“state measurer”) with distributed bad data detection and estimation, alarm processing and identification of root cause events. The prototype was evaluated and demonstrated at several substations of the collaborating utilities.
- Integration of PSERC Control Center Visualization Techniques into the TVA-hosted Southeast Wide Area Display Environment, performed by the University

of Illinois Urbana-Champaign – This project involved the integration of new PSERC visualization techniques into the TVA-hosted Southeast Wide Area Display environment and a human factors assessment of the new techniques.

- Integration of Substation IED Information into EMS Functionality, performed by Texas A&M University – Data from Digital Fault Recorders, Circuit Breaker Monitors and Digital Protective Relays were used to demonstrate improved Energy Management Systems applications during fault and restoration.

Additional technology development projects were executed as part of this CGM project. The breadth of these projects was based on several factors including the CGM project available resources. Potential project ideas were solicited from organizations such as the GridApp™ Consortium. Upon the selection of high priority project(s), CTC developed and submitted a project management plan, providing specifics about the scope, budget and schedule, as well as the cost share. CTC's participation with these projects was in the form of technical management, technical performance and coordination of research projects; selection of research project(s) for further engineering development, or a combination of both.

The previously mentioned three university projects were reported on extensively in earlier program deliverables and will not be discussed further in this report. The following sections detail the more recent advanced technology projects that were undertaken by CTC, in partnership with GridApp™ members, other electrical utility organizations, electrical equipment/systems suppliers and/or universities.

4.2.1 Advanced Fault Analysis Software System for Distribution Power Systems (AFAS) – CTC

Problem / Need

Electric utilities have emphasized that the ability to automatically detect any type of faults, as well as anticipating the type and location of momentary and permanent faults in distribution power systems, is crucial to their planning and operational activities. Quickly and accurately detecting temporary and high impedance faults/failures including voltage dips/sags and distortions will help utilities increase the reliability of their distribution systems.

Utilities need to enhance their fault diagnosis technologies for distribution circuits to enable anticipation, location, isolation and restoration of faults and failures with minimum human input and faster response times. Specific needs include locating “nagging” temporary faults that cause momentary outages, detecting high impedance faults, reducing patrol time to locate faults on inaccessible facilities (including rural and underground), reducing the overall outage time, improving restoration time, and increasing service and component reliability.

Goals and Objectives

CTC recently developed a fault-locator software tool called Distribution Systems Fault Locator (DSFL), which is capable of predicting the location of permanent faults in

distribution power systems. To enhance the DSFL fault location capabilities, the Advanced Fault Analysis Software (AFAS) tool was developed under the AFAS Phase II project. AFAS is a decision support tool that can be used in planning, operational or preventive maintenance modes. AFAS utilizes PSCAD to simulate fault transients of distribution systems to improve the fault location accuracy of the DSFL and augment it with the capability to predict the location of temporary faults (low and high impedance). The objective of the AFAS Phase III project was to further enhance the AFAS tool by performing the following activities:

- Develop a graphical user interface (GUI)
- Perform validation testing through analysis of data recorded through power quality (PQ) monitoring at American Electric Power (AEP)
- Develop and validate PSCAD fault automation, including index modules to enhance the digital library of fault signatures and to process experimental recordings
- Develop an automatic disturbance recognition system (ADRS) for fault phase classification and location.

Accomplishments

The AFAS platform consists of advanced software analysis tools and concepts for fault detection, classification and location at the distribution level. The system requires that a library of fault signatures be generated in advance to facilitate the fault location algorithm. In order to classify and locate a disturbance, the measured waveforms are processed and their calculated voltage and current (V&I) indices and their wavelet V&I indices are compared with the pre-processed digital fault signature library in near real time.

The following power system analysis tools were integrated under the AFAS platform:

- Distribution Engineering Workstation (DEW) distributed by EDD
- Advanced Energy Management Power Flow Analysis System Technology (AEMPFAST) by Optimal Technologies Inc.
- CymDist by Cyme International
- Power Systems Computer Aid Design (PSCAD), by Manitoba Research Center
- Distribution Systems Fault Locator (DSFL) developed by CTC under the AFAS platform.

A number of enhancements were made to the AFAS interface and to the PSCAD custom simulation configuration. The original AFAS tool was accessed solely via a console application. In Phase III, a GUI was developed to provide a more user-friendly means of utilizing the tool. The new GUI included a logon form, an input form to enter simulation parameters, communication between the GUI and console application, the ability to view output data files, and the ability to launch other software modules such as PSCAD. The new interface also allowed the user to manage outage call and PQ monitoring data files specific to an outage event.

PSCAD fault automation was added to AFAS through several other enhancements. Two new filter programs were developed to automate the process of converting DEW and CymDist models to PSCAD. A special PSCAD component library was created to allow PSCAD circuit coordinates to use the GIS coordinates of a circuit and make the automated circuit layout appear identical to that of the DEW or CYMDIST layout. Various types of faults can be simulated for a given location and varied using recorded parameter values. And finally, a methodology was developed to generate an index signature database using the PSCAD simulation records.

PQ monitoring at AEP, Fort Wayne, IN, was initiated in June 2007 and continued in 2008. Twenty-two (22) circuits were selected by AEP that have BMI/Dranetz PQNode[®] systems permanently installed at corresponding substations. The detailed monitoring at AEP-Indiana occurred on their Harper substation, Minich (4928822) and Deer Creek-East (4051922) circuits. These two circuits have voltage and current recording capability through a PQNode[®] power quality monitor and a Nova TS modern recloser. A significant number of faults were captured/recorded at the Harper substation and at the west and east reclosers of the Minich circuit. AFAS's ADRS validation and preliminary testing was done using the acquired fault data.

After thorough validation of PSCAD models for AEP and DTE distribution systems, a wide range of transient simulations were performed to develop a comprehensive library of fault signatures for use in advanced fault/failure location and diagnosis of momentary and permanent faults. Both the RMS and time-waveforms of voltages and currents were used. The available faulted circuit data (from DTE and AEP) for momentary and permanent faults were used to validate the results in the signature library, as well as to investigate and develop a methodology to create the signatures based on the simulation data available from PSCAD studies. Lastly, modeling and analysis studies using the developed computational modeling platform were performed to demonstrate predictive capabilities of AFAS.

An automatic disturbance recognition system (ADRS) tool was developed that can automatically detect, classify and locate any type of fault in distribution power systems. The ADRS involves a Discrete Wavelet Transform (DWT) tool for fault detection, fuzzy logic with neural networks (using FuzzyTechTM) and Decision Trees (DT) tools for fault phase classification and location.

AFAS is a powerful transient software tool that can be used for both planning and operational needs to study, detect, locate and anticipate faults/failures in distribution power systems. It was demonstrated that the digital library of V&I fault signature indices can indeed be used to determine the location of momentary and permanent faults.

4.2.2 Distribution Wireless Communication Network – CTC

Problem / Need

Today's electrical system must be run ever closer to maximum capacity, while at the same time reducing outages and negative operating conditions. Obviously these two

demands are at odds with each other. To handle this challenge, the system must be operated more intelligently and monitored more closely, and control operations must be accomplished more efficiently and in a more timely fashion. Many distribution automation (DA) devices were originally designed to operate independently, having no control coordination with the balance of utility controls. However, today many of these devices have been upgraded to incorporate intelligence that permits them to acquire and communicate data on operating conditions. They also can now operate as a coordinated component of the larger system. Adding two-way communication to these devices is required to enable this enhanced system operation.

Input was obtained from a wide variety of utility sources early in the Center for Grid Modernization program, showing that wireless mesh communication could provide high reliability with modest implementation costs. A Wireless Technology Assessment was then undertaken in order to fully understand the extent to which wireless technologies were being applied to the electric utility industry. A number of technical gaps were found to exist with wireless technologies currently on the market, making it very difficult for a utility to implement one single ubiquitous wireless solution for all DA efforts. The three most significant areas of improvement were:

- A greater choice of radios with programmable memory that can be used to interface with serially connected devices and the radio network itself, which is one of the essential elements of a mesh network deployment
- Better backup battery technologies that enable radios with moderate data loads to be fully charged in the event of an outage, to be fully functional for the duration of an outage, and to maintain a minimum charge capacity for the lifetime of the radio
- A low enough per-unit cost for hardened radio devices with the aforementioned features that a large-scale mesh network deployment is financially feasible.

Goals and Objectives

The primary goal of this project was to perform evaluation and integration efforts that would improve the art of wireless communications and aid further implementation. An effort was laid out to address these technical gaps by integrating commercial off-the-shelf (COTS) wireless communication capabilities. The technical work of this project was aimed at providing an enhanced understanding of wireless mesh communication options to foster broader utility deployment. The execution of this technical work would provide insight into the systems, components, interfaces, planning, complexities and limitations of wireless mesh communication networks in DA applications.

Early in this project it was recognized that there may be significant value in building a DA communication network by modifying the application of related COTS products. In this case Innovative Wireless Technologies (IWT) was identified for their products used in the management of large city street light systems. The intent was to take full advantage of the radio network already in place, augmenting the benefit of the network with modest implementation costs.

The essential element of the IWT network product is a streetlamp photo switch with an integrated mesh repeater radio, known as a NEMA radio. These devices have the advantage of simple, manual quarter-turn installation to replace the original basic photo switches. This simple placement is critical for efficient utility implementation. In addition, IWT's mProm™ radio offers programmable memory and serial connections to external devices.

The overriding purpose of the hardware portion of this effort was to assess the possibility of establishing wireless mesh network communication to DA devices using COTS system components such as the hardware and software offered by IWT.

Accomplishments

The following technical work was conducted in order to utilize the COTS IWT system for DA.

- The serial communication interfaces from DA devices to mProm™ radios were developed using the DNP3 protocol.
- IWT's wireless mesh network management software, mProv™, was adapted to allow viewing and interaction with DA data at the server.
- Since the NEMA radios currently do not include power backup for periods of grid power loss, these needs were reviewed, documented and approaches defined to add primary or secondary battery backup.
- During initial testing, it was determined that the RF output of the NEMA radios was insufficient to reliably link through some distances and/or obstacles that were determined necessary. Instead of increasing power draw on the radios output (requiring more significant battery backup), work was performed to identify and test appropriate external antennas that would enable more resilient communications without causing exceptional installation efforts.
- The mesh radio network (50+ radios) was installed on two CTC sites and the local University of Pittsburgh at Johnstown engineering campus (roughly 1 mile from the CTC sites), in order to operate a representative network and deal with realistic implementation issues.
- Operation of the DA devices, mesh network, server and operator interface screens were set up, tested and validated for a representative group of utility and DOE personnel.

Figure 7 illustrates the concept used in implementing CTC's wireless mesh network.

One of the biggest roadblocks to greater penetration of wireless mesh communications within distribution networks is a general lack of understanding of all the technical issues involved. Significant knowledge was gained from utilizing IWT's streetlight monitoring network to develop a DA application that augmented their existing functions with additional data traffic. Utilizing this knowledge base and methodology to develop future straight-forward, cookbook implementation solutions will do much to broaden implementation of wireless mesh networks within the utility industry.

St. Thomas and St. John. This was the first demonstration of the SuperCalibrator on a complete transmission system. Figure 8 shows a typical distributed state estimator.

Figure 8 – Typical Substation State Estimator

GridApp™ members and invited guests had the opportunity to participate in a demonstration of the Distributed State Estimator at VIWAPA. VIWAPA has deployed the DSE and is now training grid operators.

4.2.4 Phasor Measurements Business Case Analysis at Southern Company – CTC, Southern Company

Problem / Need

Utilities need guidance to fully understand the value of synchronized phasor measurement technology and build a business case for its implementation. The California Institute for Energy and Environment Phasor Measurement Application Study, known as the KEMA Study, was prepared for the California Energy Commission's Public Interest Energy Research Program by KEMA Inc. in October 2006. The KEMA Study documented the current state of the art of various phasor measurement unit (PMU) applications, potential new PMU applications, the potential infrastructure costs and gaps, and the expected benefits for use of the applications in grid operations. It also presented guidelines that provided a methodology for evaluating the benefits and costs of deploying phasor measurement technology applications and gaining support from stakeholders. Since the study was released, no known business case analyses were performed using this methodology.

Goals and Objectives

One objective of this project was to develop a business case for deploying synchronized phasor measurement technology, based upon the guidance provided by the KEMA Study. Another objective of this project was to validate that the Business Case Analysis Guidebook. The KEMA Study provided the information, tools and guidelines needed for a utility to understand phasor measurement technology, perform a cost-benefit analysis, develop a deployment plan and achieve buy-in from the necessary stakeholders, all in a cost-effective manner.

Accomplishments

Southern Company, whose PMU program was still in its early stages, formed a business case analysis project team that consisted of personnel from both Southern Company and CTC. The project team encompassed several departments within Southern Company's organization in order to incorporate a wide range of expertise and insight that would prove essential to the success of the project.

The team identified applications that could benefit from PMU technology and selected specific applications that were relevant to Southern Company's needs. They focused on each application individually to gain a thorough understanding of its benefits, PMU implementation requirements and costs. Stakeholders were identified for each application to be sure that input from all potential users was included in the analysis process. Finally, the team created a PMU deployment plan, estimated the associated costs and attempted to perform a financial analysis. Figure 9 illustrates the business case analysis process.

Figure 9 – Business Case Analysis Process

While validating the Business Case Analysis Guidebook from the KEMA Study, the team determined that the most significant obstacle they experienced was the difficulty calculating the cost of operation for PMU applications. Since PMU implementations are in a stage of relative infancy, it was difficult to perform a meaningful financial analysis on the full benefits of the technology. The team concluded that currently there was insufficient information to do a direct cost/benefit analysis on the large-scale deployment of PMU technology in Southern Company's power system.

The team determined that a phased deployment plan seemed most advisable. The current Southern Company deployment status of five PMUs is considered to be the first phase. The value of the technology will increase from a Southern Company perspective as the level of utilization increases. As each additional PMU is installed, the efficiency of the installation, setup and operational processes will increase incrementally as the experience of previous installations is incorporated into subsequent setups. This approach would

also give the industry time to mature in developing additional hardware, software, applications and standards.

Several suggested improvements to the business case analysis process were identified.

- The KEMA Study provides an excellent structure for performing a business case analysis for the use of PMU technology, but utilities need more tools to make it cost-effective enough to justify going through the process. Otherwise, it becomes too time-consuming and costly to come up the learning curve to fully understand the technology, the KEMA study and the business case analysis process.
- Utilities also need up-to-date, accurate information about the state of the synchrophasor industry—available hardware, applications, vendors, training materials, regulations, etc.—in one easily accessed knowledge base. The industry is in its infancy but also changing so quickly that it is very difficult to locate data and information necessary to support such a business case analysis.

While the team experienced many challenges in following the KEMA Study's Business Case Analysis Guidebook, they also achieved many successes in the process.

- The entire team gained a thorough understanding of phasor measurement technology and an appreciation for how PMUs might benefit their transmission system in the future.
- The knowledge gained in the current state of the synchrophasor industry will enable the team to better drive constructive changes, such as architecture and configuration standards, through their participation in organizations like NASPI.
- An appreciation was gained for current uses of PMU data within Southern Company, and a realization that state-of-the art applications for PMU data are needed to drive internal acceptance and demand. They began to look for ways to better leverage the five PMUs that are currently installed, driven also by the Florida blackout in February 2008.
- The team came to agreement upon a PMU deployment focus of “230 kV and above” as a second phase of their deployment plan and gained a thorough understanding of the costs associated with that approach.
- Although a complete financial analysis could not be completed, several key benefits were identified for the installation of PMUs in the Southern Company electric system, along with associated potential cost savings that could be used in future evaluations and justifications.

Both Southern Company and *CTC* agree that performance of a business case analysis based on the KEMA Study guidelines is a worthwhile endeavor and can have significant benefit for electric utilities. With process improvements such as those identified during this project, the analysis process can be even more successful, providing long-term benefits to both electric utilities and the industry in general.

A final report was developed for this project by the participants and was previously submitted in the April 2008 Quarterly Status Report.

4.3 Program Management

The original Center for Grid Modernization cooperative agreement was awarded on September 30, 2005. On September 29, 2006 the cooperative agreement was amended with additional funds and an extension on the period of performance through March 30, 2008. This amendment added management of the GridAppTM Consortium to the CGM scope. Near the conclusion of the agreement, a three-month no-cost period of performance extension was requested to allow additional benefits in the form of validation data and improved technology transfer from several of the projects. DOE granted this extension on February 20, 2008, extending the period of performance through June 30, 2008.

Program management for this cooperative agreement encompassed the overall functions necessary to ensure that technical requirements, schedule commitments and program budget were met. Due to the complex nature of the CGM effort, project tasking and schedule were documented in a project management plan, which was provided as a formal deliverable. After the cooperative agreement was extended, the project management plan was updated to accurately reflect project progress and scope modifications.

Program management efforts included:

- Prepared and submitted the CGM project management plan and subsequent updates
- Selected three university technology projects for execution under CGM funding
- Solicited and reviewed candidate advanced technology development projects - selected most favorable for execution. Committed funding and resources as necessary
- Identified and selected cooperative, high-priority grid modernization technology projects that were executed as part of the GridAppTM Consortium under the CGM project
- Continually monitored and refined project budgets for accurate expenditures within the GridAppTM and advanced technology projects throughout the period of performance
- Solicited and managed cost share commitments from universities and GridAppTM Consortium participants; achieved \$1,623,421 of documented cost share
- Investigated and received approval from the DOE to remove the “Common Data Format and Structure” workshop/report from the CGM project scope in order to avoid duplication of other DOE-funded efforts
- Performed continuous efforts to manage project scope, schedule and cost to meet the objectives of this agreement

- Held a CGM project status update meeting with DOE (Eric Lightner) on 08/31/06
- Participated in the DOE Visualization and Controls Peer Review meeting in Crystal City 10/17/06 (three CGM university projects presented)
- Provided a presentation on 02/25/08 to DOE stakeholders in Washington, D.C. to review project accomplishments and discuss the continuation of the GridApp™ Consortium. Key utility GridApp™ members participated in the meeting in support of the program
- Participated in technology transfer efforts through conferences, GridApp™ meetings and technical efforts with industry vendors/utilities. Organized and conducted multiple technical interchange meetings, subcontractor meetings, project review meetings and technology demonstrations
- Performed continuous review, definition, and refinement of all technical projects in terms of tasking, funding and schedule
- Prepared and submitted eight quarterly progress reports to DOE covering technical/cost/schedule status
- Prepared and submitted two annual summary progress reports to DOE covering cooperative agreement technical accomplishments, along with budget and schedule information
- Completed execution of all GridApp™ Consortium and Technology Development project efforts
- Prepared and submitted this program Final Report at conclusion of the cooperative agreement.

5.0 FINANCIAL REPORT

Budget Category	Revised Approved Budget	Actual Project Expenditures thru 06/19/08	Anticipated Expenditures 6/20-30/08	Total Estimate at Completion (EAC)
Total Salaries	\$809,366	\$818,793	\$8,267	\$827,060
Travel	\$112,188	\$87,464	\$0	\$87,464
Equipment	\$28,186	\$29,421	\$0	\$29,421
Materials & Supplies	\$121,322	\$103,320	\$73	\$103,393
Subcontracts	\$990,369	\$947,688	\$37,134	\$984,822
Subcontracts - Cost Share	\$830,911	\$1,623,421	\$0	\$1,623,421
Total Direct Costs	\$2,892,342	\$3,610,107	\$45,474	\$3,655,581
Total Indirect Costs	\$1,253,824	\$1,261,047	\$21,459	\$1,282,506
Total Direct & Indirect Costs	\$4,146,166	\$4,871,154	\$66,933	\$4,938,087
DOE Share	\$3,315,255	\$3,247,733	\$66,933	\$3,314,666
Recipient Share (Cost-Share)	\$830,911	\$1,623,421	\$0	\$1,623,421

6.0 CONCLUSION

The CGM, which includes the activities of the GridApp™ Consortium, supported advanced development of high-impact technologies that were positioned for broad industry application. The CGM mission was to modernize the nation's electricity transmission and distribution infrastructure to enhance the security, reliability and quality of electricity delivery by organizing, coordinating, and leveraging resources of the utility industry, universities, and government to select and execute short-term, high-priority R&D projects in a partnering environment. The CGM channeled the funded R&D activities through development, demonstration and commercialization planning to implement and deploy successful, validated technologies.

CTC used a structured but flexible process for planning and executing technology transition activities focused on eventual commercialization to advance the strategic and successful Smart Grid technology deployment focus of the CGM. The CGM provided value for the DOE, the electric utility industry, specific utility clients and their customers via technology identification, integration, validation and broad deployment, enabling progress toward Grid 2030 visions of improved grid efficiency, operation and maintainability. The CGM used teaming where the resulting outcome extended beyond what any one organization could achieve alone.

The effective construction of the electric grid of the future will depend on the deliberate and planned transitioning of the most promising and beneficial technologies into broad deployment as quickly as possible. The CGM goal of reducing R&D cycle time and

accelerating implementation, deployment, and competitiveness to address the near, mid and long term electric system requirements was met through the projects performed within this program.

CTC communicated and collaborated with industry stakeholders to compare existing system configurations to electric system requirements and align the R&D currently in progress to meet future electric system needs. An optimal and synergistic R&D portfolio was developed, which included continuous scenario planning to anticipate the emergence of new issues, disruptive technology breakthroughs and changes in the electric utility industry.