High Penetration of Photovoltaic Generation Study – Flagstaff Community Power

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Acronyms

API	Application programming interface
APS	Arizona Public Service
ASU	Arizona State University
DAS	Data acquisition system
DMS	Distribution management system
DOE	Department of Energy
DR	Distributed resources
GE	General Electric
IEEE	Institute of Electrical and Electronics Engineers
LVRT	Low voltage ride through
ZVRT	Zero Voltage ride through
MV	Medium voltage
NEC	National Electric Code
NESC	National Electric Safety Code
NREL	National Renewable Energy Laboratory
ODBC	Open database connectivity
OLE	Object linking and embedding
OPC	OLE for process control
PV	Photovoltaic(s)
PWM	Pulse width modulation
RES	Renewable energy standards
RTDS	Real time digital simulator
SCADA	Supervisory control and data acquisition
STAR	Solar Test and Research
UL	Underwriters Laboratory

Executive Summary

Arizona Public Service Company (“APS”) expects that by 2027, renewable energy will account for 6,590 GWh in energy consumption by its customers. While much of this future energy will come from large centrally-located power plants, distributed renewable energy, sited at the point of end-use will also play an important role in meeting the needs of APS’ customers and is expected to provide 1,734 GWh¹.

With increasing penetration of residential and commercial photovoltaic (“PV”) systems at the point of end-use, PV power generation not only offsets the load, but could also cause significant shifts in power flow patterns through the distribution system, and could possibly cause reversal of flow through some branches of a distribution circuit. Significant changes to power flow introduced into existing distribution systems due to the increased amount of PV systems may cause operational issues, including over-voltage on the distribution feeder (loss of voltage regulation) and incorrect operation of control equipment, which may lead to an increase in the number of operations and related equipment wear that could affect equipment reliability and customer power quality. Additionally, connecting generation resources to a distribution feeder can introduce additional sources of short-circuit current to the distribution system². This could potentially result in increased short-circuit currents, potentially reaching damaging levels, causing protection desensitization and a potential loss of protection coordination. These effects may be further compounded by variability of PV production due to shading by clouds. The effects of these phenomena in distributed PV applications are not well understood, and there is a great need to characterize this variability³.

This project will contribute to understanding the effects of high-penetration solar electricity on the design and operation of distribution systems by demonstrating how a high penetration of PV systems affects grid operations of a working, utility distribution feeder. To address the technical challenges related to the integration of distributed PV when PV penetration levels reach or exceed 30% of the total load, technologies and methods to ensure the stable and safe operation of the feeder will be evaluated. Lessons learned will enable APS to improve the framework for future PV integration on its system and may also aid other utilities across the United States energy sector in accelerating the adoption of distributed photovoltaic generation.

¹ roughly 4.5% percent of the total energy consumed

² However, because PV is interfaced to the grid via inverters that must operate in a manner to protect sensitive power electronics, PV tends to create short-circuit contributions of far less magnitude than would be produced by distributed generation using rotating generators.

³ The Renewable System Interconnection Study, a study on understanding high-penetration PV scenarios, completed by the DOE in 2008, detailed the issues related to distributed systems technology development, advanced distribution systems integration, system level tests and demonstrations, technical and market analysis, and resource assessment. Currently, electrical distribution systems are designed and operated based on the assumption of centralized generation, with the corollary that the power always flows from the distribution substation to the end-use customers. The study relied greatly on models and noted that up to that point, there had been very few projects actually demonstrating high-penetration PV in the US, and that additional demonstrations would be of benefit. The Renewable System Interconnection Study is available at <http://www1.eere.energy.gov/solar/rsi.html>

Project Overview

In May 2009, a team comprised of Arizona Public Service Company, Arizona State University, General Electric, National Renewable Energy Laboratory and ViaSol Energy Solutions, won an award to demonstrate and study high PV penetration under a competitive solicitation from the US Department of Energy under the DOE Solar Energy Technologies Program's High Penetration Solar Deployment solicitation.⁴

Through the award, the DOE will contribute a total of \$3.3 million over 5 years to the project. The project is an 80/20 cost share and project partners will contribute \$866,997 for a total project cost of \$4.2 million. The project, led by APS, is titled High Penetration of Photovoltaic Generation Study – Flagstaff Community Power (“HPSD-Flagstaff Study”). There are three main objectives to the overall project:

1. Study the effects of high penetration distributed PV on a utility feeder and its associated customers' electric needs
2. Create and validate models to describe the interactions between weather/PV/feeder equipment and operations
3. Identify technical and operational modifications that could be deployed in future feeder designs

Figure 1: Community Power Project - Flagstaff Pilot PV Site

To support this study, APS will leverage the Community Power Project - Flagstaff Pilot⁵, which was approved by the Arizona Corporation Commission (“ACC”) in April, 2010. As a part of its Community Power Project, APS will develop, construct and manage a high penetration of distributed PV generation on a typical residential feeder in Flagstaff, Arizona. Flagstaff is also home to APS' Smart Grid evaluation⁶. The unique opportunity allows APS to deploy solar assets and infrastructure, and also allows its study partners to conduct the HPSD-Flagstaff Study.

This executive summary describes background and results from Phase 1 of the project which included the following activities:

- Feeder baseline electrical model
- Customer and PV load models
- Field data acquisition package prototypes
- Data collection and storage methodology
- Grid-support inverter – initial evaluation

⁴ DOE High Penetration Solar Projects:

https://solarhighpen.energy.gov/projects/does_high_penetration_solar_deployment_projects

⁵ APS Community Power Project: <http://www.aps.com/main/various/CommunityPower/index.html>

⁶ APS Smart Grid: http://www.aps.com/main/news/releases/release_618.html

Project Need

The following is a discussion of factors and trends that have illustrated the need for study of high PV penetration.

APS Load Growth

Although recent economic changes have resulted in a noticeable slowing of growth in energy demand, APS expects growth to return to normal levels by 2014. APS expects average annual energy growth of 2.9 percent and projects this growth will increase the total system energy requirement by almost 16,000 gigawatt hours (“GWh”) by 2025, an increase of nearly 50 percent over 2011 levels. The APS system peak demand is expected to grow from 7,000 (in 2011) to over 11,000 megawatts (“MW”) by 2025.

Demand for Distributed PV Continues to Increase

The charts below describe the rapid rate of PV adoption on the APS system. Figure 2 shows the steady increase of installed PV capacity on the APS distribution system. Current total distributed capacity is over 100 MW.

Figure 2: Distributed PV Capacity by Year

In 2010, the average residential PV system was well over 9 kilowatts (“kW”), while commercial systems averaged over 290 kW. Commercial applications over 1 MW are increasingly common. At the utility scale, APS expects multiple PV plants over 15 MW to be connected at the distribution level, which is defined as 34.5 kV or below.

Figure 3: Number of PV Projects by Year

ACC Mandate

Arizona's Renewable Energy Standard ("RES") was enacted by the Arizona Corporation Commission in 2006⁷. The RES requires 15% of APS' retail electric sales to be generated by renewable resources by 2025. 30% of the total must be from distributed energy sources. A broad range of renewable technologies qualify, including solar thermal, geothermal, biomass, photovoltaics, and wind. In a 2010 rate case settlement, APS committed to provide an additional 3.4 GWh of renewable energy, or approximately 10% of retail sales by 2015, essentially doubling the RES target for 2015⁸.

APS Integrated Resource Plan

Energy and capacity requirements are but two elements of a broader analytical framework for a responsible resource plan that includes reliability, cost, risk and environment⁹. In addition, state and federal regulatory compliance also play a large part.

The significant long-term growth, regulatory environment, and other sensitivities such as carbon costs, water availability and usage, and natural gas prices have led APS to develop a diverse portfolio of generation resources to meet customer need while balancing reliability, cost and environmental impacts. The primary components of this diverse portfolio include not only baseload and peaking resources but also energy efficiency and renewable energy resources¹⁰. Indeed, renewable resources are expected to meet over 40 percent of the growth in energy consumption by 2025, and as described above, APS is seeking to accelerate adoption of renewable energy resources beyond the Renewable Energy Standard. Continued growth in distributed energy will be an important part of this overall growth, bringing both opportunities and challenges.

Previous Study Work: R.W. Beck Distributed Renewable Operating Impacts and Valuation Study

The opportunity for distributed energy to bring value to the APS distribution system was explored in a study completed by R.W. Beck, Inc. in January, 2009. The *Distributed Renewable Operating Impacts and Valuation Study*¹¹ (the "DE Study") was a collaborative effort that involved more than 60 individuals representing 35 solar vendors, academic institutions, solar advocates, local builders, land developers, representatives of the regulatory community, as well as numerous departments from APS including Renewable Energy, Energy Delivery, Transmission, Resource Planning, Rates and Regulation. The study sought to discuss and explore the specific implications of solar distributed energy ("DE") on the APS system in an open forum with a goal of creating a factually based common understanding. The study results

⁷ Commission Decision No. 69127 (Nov 14, 2006)

⁸ Commission Decision No. 71448 (Dec 30, 2009)

⁹ APS presentation to integrated resource planning meeting stakeholders, August 1, 2011: 2012 planning considerations : <http://www.aps.com/main/various/ResourceAlt/default.html>

¹⁰ APS Resource plan application

¹¹ Study is available under "Research" at: http://www.aps.com/main/green/choice/choice_82.html

could also serve as a foundation and starting point for further analyses on a variety of topics, including the value and impact of distributed photovoltaics to the APS distribution system.

At the distribution level, pertinent conclusions by the DE Study team included the following observations:

- Solar DE brought value to APS in both the near term and increasingly over time and the value increased (to a point) as penetration increased.
- Value could be derived for the distribution system when sufficient solar DE is deployed on a specific feeder as such deployment could potentially defer distribution upgrade investments, but the solar installations must be located on a specific feeder to reduce a specific overloaded condition. To defer any capital expenses, distribution upgrade investments cannot be reduced by small decreases in annual peak demand – the reductions to the feeder or substation must exceed the projected annual growth.¹²
- Solar DE could improve customer reliability if solar DE could continue to provide energy during a local system outage by “islanding” (continuing to generate energy even without the presence of the “grid”), however the practice would require not only changes in industry standards but would also necessitate technological improvements such as advanced metering and control through AMI and Smart Grid technology¹³
- Capacity deferral, or load reduction during peak periods could be achieved through the use of energy storage¹⁴

While the DE study was able to draw these conclusions regarding the potential benefits of solar DE, the authors noted that insufficient data was available to determine some operational impacts, such as the amount of regulation reserves required as penetration increased. In addition, the authors noted some potential obstacles to full solar DE deployment, among which were the following:

- While there is value from DE, after a certain threshold there are diminishing returns (as penetration increases, the incremental benefits decrease in terms of losses, capacity and production costs¹⁵)
- Zoning limitations, geography and customer choice may limit the amount of assets deployed in an orientation optimized to achieve adequate and measurable demand reduction and savings
- Payback period is a key driver to solar DE adoption, however payback is highly sensitive to fluctuations outside of APS’s control such as federal ITC policy, technology cost and Arizona’s economy – such externalities could put constraints on customers that may negatively affect solar DE adoption.

¹² DE Study, executive summary and Technical Value – Distribution System (p3-33)

¹³ DE study, section 3 – summary of performance issues (p3-32)

¹⁴ DE study, section 3 – modeling results of cloud cover (p3-30)

¹⁵ DE study, section 6.4 – study findings – Quantification of Solar DE savings (p 6-7)

The DE study noted that while challenges to solar DE deployment existed, there were a number of near-term solutions that could potentially alleviate those hindrances, for example, despite diminishing capacity value as solar DE increased, the value may possibly be extended through the implementation of energy storage¹⁶; improved modeling and analysis may provide distribution planners a better understanding of solar DE system impacts at the local distribution level; improved public education on solar DE, its costs and benefits and appropriate application could provide increased customer acceptance and lead to more successful deployments¹⁷. Another solution proposed by the DE study was that APS may consider a “new business model in which it directly provides services that help promote solar DE market development”¹⁸ such as financing, technology development, supply partnerships and thereby work in conjunction with the marketplace in the design, billing and field support of DE solar rooftop installations.

The foregoing summary of work, done prior to the current body of work, provided the framework for APS to recognize that a unique opportunity existed to extend the work done to date by developing a demonstration and study to explore the points raised by the DE study authors.

The opportunity to explore these points resonated with APS’ internal core values to provide safe, reliable, and cost-effective electric service to its customers. At the same time, the DOE solicitation for demonstration projects was announced and the goals of that project also resonated with APSs desire to explore additional topics such as the interactions of different anti-islanding techniques, and voltage stability in high penetration scenarios.

Project Location and Platform

Determination of project area

APS is Arizona’s largest and longest-serving electric utility with over 1 million customer accounts. The electric service territory covers 34,646 square miles¹⁹ and extends roughly from the Grand Canyon in the North to Ajo in the South, and from Quartzsite in Western Arizona to Snowflake in Eastern Arizona. The area is served by over 1,260 distribution feeders.

APS selected a portion of the Flagstaff service territory for the Community Power Project in part because the area included plans for deployment of smart distribution technologies such as intelligent diagnostics,

Figure 4: APS Electric Service Area

¹⁶ DE study, section 6.5 – qualitative findings – Factors affecting solar DE deployment (p6-17)

¹⁷ DE study, section 6.5.2 – possible solutions to alleviate obstacles to full solar DE deployment (p6-18)

¹⁸ DE study, section 6.6.3 – market transformation (p 6-21)

¹⁹ APS Service Territory: http://www.aps.com/general_info/default.html

automation technologies and automated metering infrastructure (AMI). In addition to the ability to leverage smart grid technologies, another factor in selecting Flagstaff as the site of this project was that APS expected high customer participation in the project due to the high level of community support for renewable resources in the Flagstaff area.²⁰

Smart Grid Framework

In June of 2008, APS began to develop the framework for a smart grid in the City of Flagstaff. By July 2009, nearly all of the APS conventional billing meters in Flagstaff (over 30,000 meters) had been replaced by AMI meters capable of remote communication. Distribution system automation or “smart” technologies were installed at four of the six Flagstaff substations and their feeders over the next two years.

Feeder Selection

To adequately determine the impact of distributed energy on the distribution system, the saturation of DE must be at a scale where the effects are measurable and verifiable and data can be gathered with enough detail to be reviewed and studied. Engineering and field surveys completed by APS concluded that the Sandvig 4 (“SV04”) feeder in Northeast Flagstaff could support the goal of placing a sufficiently large amount of DE to adequately demonstrate the effects of those resources on the feeder. Feeder SV04’s historical annual peak load is between 10 and 11 MW. The feeder has a minimum load of roughly 3 MW. It was determined that the project target of 1.5MW on this feeder constituted a sufficient saturation to achieve the Company’s measurement goals. Due to field conditions and customer choice, the full deployment of PV may fall slightly short of the 1.5MW (current estimate is 1.3MW). Feeder SV04 serves approximately 2,700 residential and 300 commercial customers. Field surveys indicated there were sufficient rooftops of adequate size and orientation to support the field deployment of PV systems.

Community Power Project

The project described in this report is taking advantage of the APS Community Power Project – Flagstaff Pilot. The Flagstaff pilot is designed to increase the deployment of renewable energy, especially distributed energy from photovoltaic panels (PV) and provides another opportunity for people to “go solar”. Community Power members host solar electric systems on their rooftops and join with their neighbors to form, in essence, an interconnected renewable power plant. As part of the project, APS owns, operates and receives energy from solar panels on eligible customer rooftops. Participating customers will benefit from worry-free renewable energy for no up-front costs and a long-term Community Power Rate for a portion of their bill, which will remain fixed at a guaranteed level for 20 years.

Figure 5: FCPP Installation

²⁰ APS Application to the ACC – Flagstaff Pilot Program (Docket No. E-01345A-09-0227), Decision No. 71646, (Apr 14, 2010)

APS partnered with three solar installers to pre-design the baseline PV systems, conduct the field surveys to determine customer eligibility and to install the PV systems. Over 100 residential PV systems have been installed between October 2010 and June 2011.

Phase 1 Study Plan

Key goals from the current effort are not only to learn how to manage the known challenges of high penetration distributed PV, but also to identify areas where gaps in understanding exist. These expectations are key drivers for working collaboratively with the DOE and study partners and will provide APS the opportunity to not only contribute to the industry's collective knowledge base but will also allow APS to gain direct operational experience with high penetration PV.

Study Objectives

There are three main objectives for this study:

1. Observe and measure the effects of high PV penetration on the distribution feeder²¹ and on the electric energy needs of customers on that feeder
2. Based on analysis of the collected information, create and validate computer models that describe the effects and interactions between weather, PV and feeder equipment and operation
3. Combine analysis of field observations and the models to identify technical and operational modifications that could be deployed in future feeder designs

Overall study objectives will be achieved in a staged approach consisting of five phases. The focus of Phase 1 is on developing baseline models, data acquisition methodology and prototypes, and initial evaluation of a smart inverter. Phase 2 extends the baseline model to a high PV-penetration feeder, and includes models of coordinated operation of connected equipment such as reclosers, cap banks, fuses, and PV inverters. Phase 2 also includes deployment of solar and data acquisition equipment. Phase 3 delivers models that describe the theoretical limits of the amount of PV possible on the feeder. Phase 4 extends the demonstration to include grid support inverters and battery storage and also extends the computer models to explore more esoteric topics such as intentional islanding. In Phase 5, the team will share final results and analysis including a cost-benefit analysis of the project.

²¹ that is, all the components of the feeder and connected equipment, which in the case of this particular feeder are the conductor, reclosers, capacitor banks, fuses, distribution and substation transformers

Study Timetable

A summary of project phases and key tasks are described below.

Figure 7: Project phases and tasks

Project Management

The program of work was managed by APS. This structure was developed to conduct the engineering of all phases and to deploy field equipment. A Technical Advisory Committee consisting of key technical and process experts from APS provided part time support for technical and process development issues, provided independent oversight of the program and advised the Project Manager and Principal Investigator. Principal Investigators from each project partner were responsible for their respective organizations and reported to the APS Project Manager and Principal Investigator. Specific focus areas for each team are described below.

APS started deployment of the Community Power Project that provides the backbone for this program and includes the selection and interface with distributed solar electric customer sites.

ASU led the modeling, study and validation tasks to assess the impact of high-penetration PV on the APS distribution feeder.

GE co-developed modeling, analysis and validation solutions to support and supplement ASU's efforts. GE also led the smart inverter evaluation task of this project. In addition, GE also

assisted APS in development of a data acquisition platform suitable for analysis of high-penetration PV impact on the APS feeder.

ViaSol Energy Solutions led the fabrication of data acquisition prototypes and also supported initial study and analysis of residential and commercial PV installations.

NREL validated models and analysis developed by ASU and GE and also led the data dissemination of project results and analysis.

Phase 1 Results

Preliminary feeder baseline model

For a first-level understanding of the feeder operation, one must develop an electrical model of each device attached to the feeder which in this case include the substation transformer, the overhead and underground electrical conductors (feeder segments), capacitor banks and distribution transformers (shown on Figure 8).

Figure 8: Feeder electrical devices

Device	Total	Legend
Substation Transformer	1	
Feeder Segments	1810	Ph A Ph B Ph C
Capacitor Banks	3	
Distribution Transformers	921	
Residential PV Systems ²²	~200	
Green Field & Commercial PV Systems	2	

Table 1: Feeder Devices

Information about each device was shared with the teams from ASU and GE. The information was summarized by ASU and presented to APS engineering staff. If any assumptions were required, they were discussed by the team and reviewed prior to use.

To develop the electrical model, the main type of data required was graphical information system (GIS) data detailing the location of equipment, along with basic equipment information, detailed data about feeder devices, distribution transformers and conductors, load data for the entire feeder, loads for customers on the feeder and PV system configuration information. To protect customer confidentiality, each installation and its associated parameters was referenced by a “Site ID”, and only essential data was shared with the teams directly involved with the modeling work.

²² By June 1, 2011, roughly 100 residential PV systems had been installed in the field. The model developed for phase 1 used the initial project design number of 200 residential systems

Through multiple iterations of data exchange and discussion, parameters for input into the computer model were finalized. Input data was then processed using MS Excel, MATLAB Version R2009b and custom developed programs to combine and format the data into a format suitable to be imported into the computer modeling program chosen for the task, CYMDIST Version 10.

In CYMDIST, the electrical system model is built using three parts: equipment library, network model, and load model. The equipment library contains the definitions of all the equipments and devices (including conductors) that may be used in the network model. The network model is the physical model of the system, containing detailed information about what equipment and devices are present in the system and how they are connected. The load model defines the loads, including the load locations and the load data to be used for power flow study.

Figure 9: CYMDIST Feeder Electrical Model

Figure 10: Probability Density of Feeder Load

Extensive processing of load data was required to obtain load profiles suitable for CYMDIST. Using an innovative approach, GE Energy developed probability density functions to describe the predicted feeder load for each hour of the year. The work was used to develop hourly load inputs to exercise the electrical model and build preliminary steady state analysis of load, current and voltage.

The preliminary electrical model of the existing feeder was completed in November, 2010. In late December 2010, the project team collected field measurements at six locations along the feeder to begin model validation. The voltage levels predicted by the model are within a few percent of measured values and the percent imbalance between model and measurements is comparable. Based on this assessment, the model has adequate accuracy to be used for further analysis.

Figure 11: Percent Voltage Error, Model vs. Measured

Data Acquisition Prototypes

The team developed, constructed, and installed data acquisition system prototypes for monitoring customer-sited PV systems and weather. The prototypes were installed at the APS Solar Test and Research Center in November, 2010.

Through team discussions and requirements analysis, a platform was proposed and prototypes were built to enable testing and validation prior to field deployment. The data acquisition methodology must support not only the study, but must also address PV system operations and maintenance (O&M) for the life of the PV systems, grid operations, data security and field data acquisition hardware maintainability. Prototype details are described below.

Data Acquisition Prototype for Weather Station

To study environmental effects, weather information will be collected at roughly seven locations in the project area. In Phase 2 of the project, three weather stations will be installed along the feeder under study and the remaining four weather stations will be installed in Flagstaff area substations (shown in Figure 12).

The weather station data acquisition platform is based on a Campbell Scientific CR1000 data logger. The data loggers are GPS time-synchronized and configured to record data at 1 second intervals. The weather station's sensor complement includes measurement of solar radiation (global horizontal, fixed latitude), wind speed & direction, site temperature, relative humidity, atmospheric pressure and rainfall. Data will be backhauled via wireless radio network or existing substation communications network.

Figure 12: Weather Station Prototype and Locations

Data Acquisition Prototypes for Customer-sited PV

All customer sites within the study area are equipped with Automated Metering Infrastructure (“AMI”) meters that are collecting hourly energy consumption from each site (roughly 2500 customers). AMI meters also collect PV generation from each customer-sited PV system at 15-minute intervals.

During phase 2 of the project, APS will work collaboratively with customers in the study to identify a pool of approximately twenty residential PV sites that will have additional information collected by a Schweitzer Engineering Laboratories (SEL) power quality meter (SEL 734P). The meter is capable of measuring a full range of power quality parameters and is configured to record data at 1 second intervals. Data from the power quality meters will be backhauled via wireless radio. The installation locations will be based on a number of technical and customer-related criteria including, PV system size and orientation, availability of

Figure 13: Customer-Sited PV DAS Prototype

Figure 14: PV/AMI Meter locations (blue, green and orange circles)

physical room for enclosure and strength of wireless signal at the site.

Data Acquisition Prototypes for Feeder Electrical Parameters

Electrical parameters relating to the distribution feeder will be collected via existing feeder monitoring instrumentation at the substation, by voltage regulation equipment along the feeder, and six new utility pole-mounted power quality meters (Schweitzer Engineering Laboratories (SEL 735).

The core functionality of the new data collection devices is that the power quality meters are enabled with cross-device triggering which will allow the project team to measure and record parameters from six separate locations along the feeder simultaneously. The data measurements can be scheduled to be taken automatically at a certain time, or they can be taken based on a user-defined “trigger”, such as a change in irradiance levels or change in electrical parameters at any of the feeder locations. The device will operate in two modes: in “standard” mode, measurements will be taken every second; in “high bandwidth” mode, the measurements will be taken at a very fast rate (thousands of measurements every second) to ensure that as many fluctuations in grid parameters as possible are captured for model validation.

The primary measurement device, the SEL 735, was not commercially available as of June 30, 2011 and therefore, a full prototype was not built. Bench testing with a similar product, the SEL 734p, was conducted to assess the feasibility of the cross-device triggering and testing results showed that the functionality expected from the final platform should meet project specifications. The SEL 735 is expected to be available by September, 2011.

The team explored multiple options prior to finalizing the platform. The final design leverages existing knowledge, infrastructure and processes for maintenance that will allow for a more seamless integration into utility operations for the duration of the study.

Data Communication, Collection and Storage Methodology

Several months of work by a team of IT specialists was required to build connectivity between the various data collection and storage platforms that will provide information for the project. The data collection strategy leverages APS’s existing AMI infrastructure and is supplemented by a network of wireless radios. Primary data storage is accomplished using an OSISoft PI data historian. During the initial phase, the data historian required modifications to its time stamp configuration and also required modifications to its compression methodology. APS expects additional effort will be required to manage and store the various data streams as the project moves into the deployment phase.

Figure 15: New Feeder Data Acquisition Locations (Blue Stars)

Preliminary evaluation of GE smart inverter

There are multiple efforts underway to develop a framework and application tools to use the capabilities of large “utility-scale” grid-support inverters such as this. At PV plants connected at the transmission level, such capability is already expected and is being phased in newer plants. For PV plants connected at the distribution level, the expectations are less defined. GE Global Research has arranged for the loan of a GE Brilliance 700kVA Solar Inverter and its grid-support control system, the SunIQ, to the project to test and evaluate such grid support capabilities as part of this study.

There are two phases to the inverter evaluation: 1) initial evaluation locally, and 2) field deployment in Flagstaff on the test feeder. Initial evaluation began in mid-October, 2010 at the APS Solar Test and Research Center. The primary goals for this phase of the phase were to: 1) provide an opportunity for APS engineers and technicians to gain familiarity with the inverter’s capabilities, requirements and operation; 2) demonstrate the advanced features of the inverter that may be new to engineers used to standard solar inverters; and 3) develop a test plan to be

Figure 16: GE Inverter under evaluation at APS STAR Center

used in future phases of the study. One additional goal, delivery of a report detailing the requirements, capabilities and evaluation of the inverter’s integration into the APS SCADA system, was noted as requiring additional consideration to ensure that the communication methodology would meet utility cyber security concerns. The task will require additional resources and will be finalized in future phases.

At the start of the evaluation period, the inverter was not yet compliant with existing APS interconnection standards and therefore was run under supervision only during the day in the last quarter of 2010. After multiple exchanges of information between GE and AP engineering

departments and several months of operational experience, the inverter was allowed to be operated in stand-alone unattended mode in May, 2011.

Prior to this project, APS had never used inverters to support the grid at the distribution level. This project has demonstrated that when grid-support capability is desired at the distribution level, significant challenges, such as interconnection standards, will need to be addressed at the outset. In addition, other challenges, such as data and communications security, must also be addressed. The test plan for evaluating the inverter functions is presented as an appendix to this document.

Phase 1 Key Conclusions

Phase 1 has provided many insights into the process behind implementing high penetration PV projects. Some of the major conclusions from Phase 1 are as follows:

- Careful consideration must be given when designing a data acquisition system for use in high penetration PV cases. The system must be designed to capture and synchronize both electrical and environmental data with sufficient resolution to adequately capture a variety of potentially disruptive phenomenon. Transmitting these data even on a small scale can provide significant storage and communication challenges.
- Accurately modeling distribution feeders to the level necessary to analyze the impacts of high penetrations of intermittent resources is an involved process. Even though a utility may have data from various separate databases (GIS, DMS, etc.) describing their systems in significant detail, since these databases were not intended to be used for model development, gaps and inaccuracies may manifest in electrical models developed from these sources. Even with detailed analysis, building a model that accurately represents the electrical system down to the customer meter will likely be an iterative process, checked and re-checked against data from field devices.
- Utilities have gathered great experience in the application of rotating power generation equipment, and some also have experience with power electronic aided energy shaping. However, many utilities are just beginning to add large and small scale power electronics to their grid. Power electronic systems, such as the PV inverter described in this report, offer many potential benefits to utilities but behave differently than traditional generation. Lack of familiarity with this new technology and lack of results from field demonstrations can lead to hesitation on behalf of the utility in going forward with broader power electronic based solutions. A major goal of this project is to assist utilities in gaining experience and familiarity with power electronics, their requirements, and their potential economic and operational benefits.

Looking Ahead

Results from this phase of the project are beginning to be applied as the project moves from Phase 1 into the deployments in Phase 2. Activities and key learning from Phase 1 is intended to set the baseline understandings for deployment and data validation in Phase 2 of the project. The foregoing pages briefly summarize the progress to date.

Introduction

Arizona Public Service (APS) expects that over the next 15 to 20 years (2027), renewable energy will account for 6,590 GWh in energy consumption by its customers. While much of this future energy will come from large power plants, distributed energy will also play an important role in meeting the needs of APS' customers and is expected to provide 1,734 GWh²³.

With increasing penetration of residential and commercial photovoltaic systems at the point of end-use, PV power generation not only offsets the load, but could also cause significant shifts in power flow patterns through the distribution system, and possibly cause reversal of flow through some branches of a distribution circuit. These effects may be further compounded by variability of embedded PV production due to shading by clouds. The effects of these phenomena in distributed PV applications are not well understood, and there is a great need to characterize impact of this variability.

As a whole, the energy industry needs to better understand high penetration PV and provide definitive answers to some basic questions such as:

- How and where can its effects be measured?
- What are the values and challenges?
- Can it provide advantage for the benefit of energy companies and their customers?
- How is it achieved and how must it be managed once achieved?

In addition to these questions, there are other unknowns such as the costs of integrating these resources and where these resources fit on a utilities' system. To manage and find full value of these new distributed energy resources moving forward it will take an integrated set of studies and integration tools. Continuing work around high penetration solar, system design, managing and understanding variability, energy storage and other system solutions and challenges will need to be addressed. The High Penetration of Photovoltaic Generation Study – Flagstaff Community Power, a collaborative effort funded primarily by the US Department of Energy, and the APS demonstration in Flagstaff have been developed to answer just such questions. The DOE project team is approaching completion of Phase 1 of the study effort, which focused primarily on modeling, development of prototypes for data acquisition, and preliminary evaluation of a “smart” inverter.

This report describes the phase 1 results.

²³ roughly 4.5% percent of the total energy consumed

1 Overview

As PV installations at the point of end use increase, the unprecedented penetrations of solar energy on distribution feeders will likely affect the feeders in ways other than simply offsetting the demand load at the source. Effects such as significant shifts in power flow patterns through the distribution system may cause reversal of flow through some branches of a distribution circuit. These effects may be further compounded by variability of PV production due to shading by clouds. The effects of these phenomena in distributed PV applications are not well understood and there is a great need to characterize this variability.

Improving the understanding of the effects of high-penetration solar electricity on the design and operation of distribution systems will address some of the technical challenges related to the integration of distributed PV and accelerate their adoption.

1.1 Project Description

Arizona Public Service expects that by 2027, renewable energy will account for 6,590 GWh in energy consumption by its customers. While much of this future energy will come from large centrally-located power plants, distributed renewable energy, sited at the point of end-use will also play an important role in meeting the needs of APS' customers and is expected to provide 1,734 GWh. Arizona's Renewable Energy Standard (RES) requires that 30% of APS' renewable energy be generated from distributed energy sources, such as PV systems on customer homes and businesses.

Community Power Project

The project described in this report is taking advantage of the APS Community Power Project – Flagstaff Pilot. The Flagstaff pilot is designed to increase the deployment of renewable energy, especially distributed energy from photovoltaic panels (PV) and provides another opportunity for people to “go solar”. Community Power members host solar electric systems on their rooftops and join with their neighbors to form, in essence, an interconnected renewable power plant. As part of the project, APS owns, operates and receives energy from solar panels on eligible customer.

Participating customers will benefit from worry-free renewable energy for no up-front costs and an attractive long-term Community Power Rate for a portion of their bill, which will remain fixed at a guaranteed level for 20 years. APS anticipates it will install 1.3 MW of PV as part of the Community Power Project along a feeder in northeast Flagstaff which serves 2,600 residential and business customers.

Figure 17: Community Power Project

“The goal of the pilot program is to establish a partnership between the customer and the Company that will make customer adoption of DE simple and eliminate customer concerns,

whether technical or economic.”²⁴ In addition, the pilot program will also allow APS to integrate DE into the emerging group of technologies comprising the “smart” grid.

APS believes the Community Power Project will provide information leading to better understanding of the reliability and life cycle costs of residential and commercial renewable energy systems and will also allow for more effective deployment of DE in the future.

On April 1, 2010, the Arizona Corporation Commission unanimously approved the Community Power Project and the Company began to seek out customers serviced by SV04 to participate in the Project. Customer participation was voluntary. Eligibility for participation was contingent on passing criteria that reflected the technically necessary conditions for equipment installation and economic provisions to ensure the customer received the program benefits as intended.

The eligibility criteria included:

Grant of Easement – property owners provide a utility easement to allow APS to place and maintain solar assets on the customer’s rooftop. The easement includes aerial rights to ensure that the photovoltaic array will have continuous and unobstructed exposure to available sunlight and also covers any additional equipment such as inverters, meters and interconnection equipment.

Customer energy consumption must be in excess of an average of 400 kilowatt-hours (“kWh”) per month (4,800 annually)

Customer must occupy the host property for a minimum of six continuous months each year

Customer rooftop space – rooftops must have sufficient space to locate a pres-designed and standardized PV array (sized 2kW, 3 kW or 4 kW) – eligible customers were matched with the most appropriate system given their usage and size of rooftop.

Age of rooftop – the rooftop must be less than 10 years old or be inspected to verify that it has sufficient integrity to support the long-term installation of the photovoltaic array

Rooftop orientation – the rooftop space must have a south, southwest or southeast orientation with little or no shading (based on field survey results, rooftops with east and west exposures were later allowed)

Accessibility – APS must have unrestricted access to the rooftop for maintenance purposes

Structural integrity – the roof and building structures were evaluated for soundness and structural adequacy to support the physical system installation

²⁴ APS Application to the ACC – Flagstaff Pilot Program (Docket No. E-01345A-09-) - Exhibit A

APS partnered with three solar installers to pre-design the baseline PV systems, conduct the field surveys to determine customer eligibility and to install the PV systems and provide maintenance for a period of three years. By October 2010 the installer contracts were in place and during the

last three months of 2010 over 21 residential PV systems were installed. From late December 2010 to mid February, 2011, snow accumulation prevented any new installations but by early March, installations had resumed. To date, over 110 residential PV systems have been installed.

A significant amount of work was completed to modify existing or create new businesses processes to accommodate utility-owned assets on customer rooftops, a notion that APS had previously not

developed. The pilot project has leveraged business processes in all departments related to energy delivery, customer relations, distribution engineering, renewable energy, solar O&M, and has required new businesses processes and tools to be developed by IT. APS anticipates the asset procurement, deployment and program implementation costs to be over \$10 million²⁵, and as described above, the commitment to the customer to maintain and operate the solar assets is for a term of over 20 years.

The effort and cost expended on the pilot project is large, however it follows a long tradition at APS for strong support of renewable energy, a commitment APS has maintained for over 40 years. Renewable energy has been an increasingly important component in APS's resource mix and APS believes expects renewables, especially photovoltaics, to be a key component of that energy mix in the future.

Figure 18: Early APS photovoltaic plant

²⁵ APS filing of Pilot project to ACC:

Figure 19 Flagstaff Energy Information Network - APS "Smart Grid"

The pilot is a part of APS' smart grid initiatives for operation and data collection. Flagstaff is at the forefront of APS' smart grid technology initiatives and APS has been installing automated network switches and remote monitoring equipment that help improve the responsiveness and reliability of the electric distribution system. This improvement includes the installation of more than 35,000 digital "smart" meters at APS' customers' homes and businesses. Together with the Community Power Project, smart grid technologies will help APS learn how distributed energy impacts its system and results will be evaluated for applications beyond the Community Power Project.

1.2 Goals

The major goals of this project are as follows:

- Study the effects of large amounts of distributed PV on a utility feeder and its associated customers
- Create and validate models to describe the interactions among weather-PV-feeder equipment and operations
- Identify technical and operational modifications that could be deployed in future feeder designs

2 Preliminary Steps

Prior to project commencement and in the very early project stages, several decisions were made that had significant impact on the project. This section provides a brief overview of two of those decisions: identifying the project test feeder and the modeling software selection.

2.1 Feeder selection

The feeder selection process began with a review of the feeders in the project area. Historical load data from the list of over 20 feeders was then assessed to identify feeders which had a load profile that could be impacted by the addition of PV totaling roughly 15% of the feeder peak load. The feeders were also profiled to check the ratio of residential to commercial customers and feeders that had roughly equal commercial and residential customers were flagged as potential candidates.

After the initial selection, more detailed field surveys were conducted on specific candidate feeders to assess suitability. Throughout the entire process, feeders were eliminated for a number of reasons including the following:

- Excessive length that may pose challenges to the line of sight metering equipment
- Lack of solar access due to heavily forested areas
- Lack of sufficiently available land area for 500kW PV array
- Lack of sufficient area in substation for future energy storage
- Lack of sufficient residential rooftops with south-facing exposure
- Lack of sufficient mix of commercial to residential customers
- Lack of sufficient number of potential candidates for domestic solar water heating

Sandvig 04, the feeder selected for this project, was the third feeder to be field-surveyed and met the greatest number of project criteria. A key expectation of this project is to reassess the selection criteria in future phases and determine how the methodology could be modified for application to other feeders that may benefit from high-penetration PV.

2.2 Modeling software selection

Another major preliminary consideration for this project was the selection of modeling software. Analyzing the impacts of high penetrations of intermittent distributed resources (DR) on

distribution systems can test the limits of modeling and simulation packages. Some of the major considerations for selection of modeling software include the following:

- Balanced versus unbalanced load flow
- Model detail (ability to model distribution transformers, secondary systems, etc.)
- Ability to develop automated and custom analyses
- Ability to automate circuit construction
- Integration with external engineering tools (MatLab, etc.)
- Availability of distributed resource models
- Support for advanced, time-varying load and generation models

To accomplish the modeling and simulation tasks, the project team chose CYMDIST as a distribution modeling package along with MatLab for analysis and various automated circuit building functions. Recognizing the large number of open source and commercially available distribution modeling and analysis tools, a goal for project reporting will be to include evaluations of the software performance and discussion of modeling related issues and concerns. In this way, the project team hopes to provide guidance for others making similar decisions.

3 Feeder Modeling

The main objectives of this task were to develop and validate the models and analytical tools required to study the impact of high penetration PV on the design, operation and performance of typical distribution systems under various operating scenarios. The models and simulations serve two major purposes: (1) a design tool for the proposed Community Power Project demonstration project; and (2) a tool for studying various "what-if" scenarios. What-if scenarios allow the team to simulate different contingencies, PV penetration levels and customer demands which cannot be practically tested on a real system but need to be accounted for in the design of an actual system. Models will be developed for the prototype power distribution system where high penetration of PV is introduced, the distributed and centralized PV generators, and different types of loads. Validation of these models, including a sensitivity analysis and an investigation of strengths and weaknesses will be conducted in future phases to confirm the reliability of the models. The modeling focus consists of three distinct but interdependent layers as illustrated in Figure 20.

Figure 20 Modeling Focus Areas

Key accomplishments for this task are as follows:

- A model was developed that included the various feeder component impedances, capacitor banks, lumped line/cable impedances throughout the length of the feeder, all the distribution transformers, and PV generators.

3.1 Modeling Process

The modeling process is illustrated in the flowchart in Figure 21. It starts with acquiring all the input data required for the modeling from APS. Data are processed using various software tools and developed programs. Finally, all the processed data are combined, entered or imported into CYMDIST to build the distribution system model, with the one-line diagram automatically generated. In CYMDIST, a distribution system model consists of three parts: equipment library, network model, and load model.

The equipment library contains the definitions of all the equipment (including conductors) that may be used in the circuit model. The network model is the physical model of the system, containing detailed information about what equipment is present in the system and how each device is connected. The load model defines the loads, including the load locations and the load data to be used for power flow study. Extensive load data processing and analysis may be needed to obtain load data appropriate to be used in the load model.

The details of the modeling process are described in the following subsections. The modeling of PV and inverter characteristics, which will be integrated into the distribution system model in Phase Two, is also presented.

3.1.1 Input data summary

Below is a summary of the input data supplied by APS.

- GIS data (in both *personal geodatabase* and *file geodatabase* formats), which give locations and basic information (e.g. equipment type, rating, etc) for lines and equipment on the feeder
- APS construction standards for line conductors and spacing
- Transformer impedance data
- Load data, including
 - hourly/sub-hourly load data for a few customers corresponding to different rate plans
 - hourly load data at feeder head
 - monthly energy consumption data at the customer level
- System equivalent impedance at the substation
- PV panel and inverter manufacturers
- In-field voltage measurements for model validation
- The details about these data and how to use them are described in the subsequent subsections.

Modeling Process

Figure 21 Modeling process flow chart

3.1.2 Feeder Overview

A quick overview of the feeder can be achieved by opening the GIS data (in *file geodatabase* format, which is a *.gdb* folder) in ArcGIS Explorer®, a free tool by ESRI®. This is shown in Figure 22. Figure 22 also shows a table that summarizes the components on the feeder.

Equipment Name	Total	Legend
Feeder segment	1810	Red line
Transformer	921	Blue dot
Fuse	186	Orange dot
Capacitor bank	3	Blue pushpin
Switch	18	Green pushpin
OCR	2	(not shown)
Switching cabinet	66	(not shown)
Voltage regulator	0	N/A

Figure 22 GIS view of the Sandvig 04 feeder in ArcGIS Explorer®

3.1.3 Equipment Modeling

Equipment modeling is the process of finding all types and subtypes of devices existing on the feeder and modeling them in the CYMDIST equipment library. Each type (subtype) of device modeled in the library is given a unique Equipment ID (called EqID). In order for the network modeling process to automatically identify the EqID for a device, the EqID is formed using information from the GIS data, such as the type and/or rating of the device.

The modeling of conductors/lines, transformers, capacitor banks, PV generators and feeder equivalent source at the substation are discussed in detail in the following sections.

3.1.3.1 Conductors / Lines

The determination of series impedance for overhead and underground lines was a critical step before the analysis of the distribution feeder could be done. The series impedance of a single-phase, two-phase or three-phase distribution line consists of the resistance of the conductors and self and mutual inductive reactances resulting from the magnetic fields surrounding the conductors. The impedance of APS line configurations and conductor types used on the test feeder were calculated using textbook equations and verified against those calculated by CYMDIST.

3.1.3.2 Distribution transformers

In order to model the transformers in CYMDIST, the kVA rating, the high side and low side voltages, the impedance percentages and X/R ratio are required. For the three-phase transformers, the kVA rating, impedance values and X/R ratio were provided by APS.

In the case of single-phase transformers, for the given kVA rating and impedance percentage provided by APS, X/R ratio were found from the Red Book²⁶. For those transformers whose impedance was not mentioned by APS, the average impedance percentage was assumed to be 2.7. In most cases the transformer low side voltage was assumed to be 120V for single-phase transformers unless mentioned in the GIS data.

Table 3 shows the parameters for single-phase and three-phase transformers respectively. These values are entered into CYMDIST and the transformers have been labelled in a way which shows the KVA rating and low side voltage of the transformers. For example, '100_120' means the kVA rating of the transformer is 100 and the low side voltage is 120V. This labeling rule is used to make it easy to refer to this transformer definition when adding an instance of this transformer to the *network model* based on the GIS data. In all, 25 different types of transformers are modeled in CYMDIST.

Y-ground/Y-ground configurations for all the three phase transformers have been assumed. This can be easily changed when the information on the actual configuration in the field is available.

[1] ²⁶ IEEE 141-1993, *IEEE Recommended Practice for Electric Distribution for Industrial Plants* (IEEE Red Book).

Table 2. Parameters for single-phase transformers

Rated	Sec. voltage	Z	X % from	R % from	X/R
5	120	2.7	0.8	2.1	0.380952
10	120	2.7	1.1	1.3	0.846154
15	120	2.7	1	1.3	0.769231
25	120	2.6	1.1	1.1	1
37	120	2.7	1.3	1	1.3
50	120	2.3	1.5	0.9	1.666667
75	120	2.1	1.2	0.8	1.5
100	120	2.7	1.5	0.8	1.875

Table 3. Parameters for three-phase transformers

Rated	Sec. voltage	Z	X	R	X/R
112.5	120	1.55	1.12	1.07	1.0467
112.5	277	1.54	1.01	1.16	0.875128
150	120	1.60	1.12	1.14	0.977198
150	277	1.70	1.26	1.13	1.115044
225	120	1.43	1.21	0.77	1.574835
225	277	1.72	1.53	0.80	1.914221
300	120	1.84	1.61	0.88	1.825264
300	277	1.90	1.72	0.82	2.095122
500	120	2.38	2.23	0.84	2.648021
500	277	2.26	2.14	0.75	2.86612
750	120	5.56	5.48	0.94	5.833041
750	277	5.46	5.42	0.62	8.807587
1000	120	5.35	5.26	1.00	5.267525
1000	277	5.64	5.60	0.71	7.927135
1500	277	5.58	5.54	0.67	8.273616
2000	277	5.59	5.55	0.69	8.022399
2500	277	5.97	5.93	0.71	8.309958

3.1.3.3 Capacitor banks

There are three capacitor banks on the Sandvig 04 feeder, two of which have the same specifications. Thus two types of capacitor banks are modeled in the CYMDIST equipment library. The rating of the capacitor bank is used to form the *EqID*.

3.1.4 Equivalent source at the substation

A Thevenin equivalent source representing the generation, transmission system and the substation that serve the feeder must be defined in order to carry out power flow and fault studies on the feeder. In CYMDIST, the equivalent source is defined as a special equipment type called *Source*.

Depending on the data availability, one can use two approaches to find the impedance of the equivalent source

1. Use the equivalent impedance looking from the **high** side of the transformer back into the transmission system, **plus** the impedance of the substation transformer
4. Use the impedance looking from the **low** side of the substation transformer back into the system.

For Feeder Sandvig 04, it is served from the transformer in bay 3 at Sandvig Substation. The impedance of this transformer is known:

Positive sequence $Z = 7.1\%$

Zero sequence $Z = 6.92\%$

However, the impedance looking from the high side of the transformer into the transmission system is not given. On the other hand, the impedance looking from the low side of the transformer back into the system is given as:

Positive sequence $Z = 0.1000 + j 1.1023 \Omega$

Zero sequence $Z = 0.0507 + j 0.8440 \Omega$

Thus, approach 2) has been adopted to define the impedance of the equivalent source (use impedance from low side of substation transformer looking back into system).

The voltage of the equivalent source is set based on APS's operation practice, which is 1.05 p.u.

3.2 Building the Model

The model building process involves converting the GIS data into a CYMDIST network model of the feeder. This process is primarily conducted with a set of MATLAB programs. Figure 23 shows the flow chart of the steps performed in MATLAB. After the MATLAB programs create the TXT files (in CYMDIST format), they are imported into CYMDIST and the circuit model, including the one-line diagram, is automatically created.

Figure 23. Flow chart of the network modeling process in MATLAB

3.2.1 The GIS Data

In the GIS data from APS, each component is defined as a *feature*. All equipment devices (i.e. transformers, fuses, switches, OCRs, etc) are *point* type features, meaning they have a geometry of a point when shown on the GIS map. The distribution lines (named as *Primary1* in the GIS data) and buswork (short lines housed by switching cabinets) are *line* type features.

3.2.2 Converting and Reading the GIS Data

MATLAB cannot read the personal geodatabase (.mdb file) or the file geodatabase (.gdb folder) directly. However, it does provide a function (*shaperead*) to read shape files (.shp). Thus, an ESRI tool called ArcCatalog was used to convert the .mdb file to shape files for use with MATLAB. The shape files essentially contain the same information as the .mdb and .gdb versions. After reading the shape files into MATLAB, each feature is represented by a structure (a data type in MATLAB) with fields corresponding to the attributes in the GIS data.

3.2.3 Topology Identification

The first step of the modeling process after reading the GIS data into MATLAB is the topology identification. Topology identification is the process of finding the electrical connections of the line segments and the equipment devices. This step is necessary since, although the GIS data indicates the locations of all the lines and the equipment devices, it does not contain the explicit information about which line segments are connected together electrically. The output of this step is a set of *Nodes* (buses) and *Sections* (branches) and the indices of the *From Node* and *To Node* for each section.

Figure 24. Flow chart of topology identification. Here *Line* means a line segment in the Primary1 feature class in the GIS data.

The flow chart of this process is shown in Figure 24. When determining whether the start or end point of a line is ‘at’ (connected to) a *node* in the *Node List*, a small distance (.01 ft.), has been used as the criterion. That is, two start or end points (but not the intermediate points) of two different lines will be regarded as connected if they are within a distance of 0.01 foot. This small distance is used to tolerate some small error in the GIS coordinates. Nonetheless, for the current GIS data provided by APS, the coordinates of the points that are supposed to be connected matches exactly (i.e., their distance is zero).

3.2.4 Island Analysis

After identifying the nodes and sections, the next concern is whether the topology is a fully connected network. To determine this, an island analysis algorithm as shown in Figure 25 has been developed. After performing the island analysis on the initial GIS data, 144 islands were found.

Figure 25. The island analysis flow chart

The cause of the presence of so many islands was later identified: the initial extract of GIS data did not include the switching cabinets, which are the cabinets containing buswork that connect different parts of the circuit. A subsequent new GIS extract that included the switching cabinets solved the problem. Figure 26 and Figure 27 shows the GIS plots with and without switching cabinets. After including the switching cabinets, the island analysis was performed again and resulted in a fully connected circuit.

Figure 26. Missing switching cabinets (a) single phase case, (b) three phase case)

Figure 27. Buswork in switching cabinets (a) single phase case, (b) three phase case)

Before receiving the switching cabinet data from the new GIS extract, a MATLAB program was developed to help reduce the number of islands. This program can be useful in case switching cabinet data are not available from GIS. The program first automatically connects an island to the main island if it meets the following criteria:

1. It is single phase.
2. There is only one place where it has an end node that is very close to an end node of the main network and also both have the same phase.

These criteria are conservative so that false connections are avoided. It was found that only ten islands were left after this step was performed. The final step of the MATLAB program displays the feeder in a figure with the remaining islands shown in a different color and allows the user to interactively connect them to the main island manually.

3.2.5 Associate Conductors with Sections

This step is to link the lines and cables actually on the feeder with the line and cable types defined in the equipment. CYMDIST uses *LineCableID*, which is the label of the line/cable components in the equipment library for this linking. The following naming rule is used for this *LineCableID*:

<OH/UG>_<number of conductors>_<conductor code>

For example, a one-conductor 2R overhead line will have a *LineCableID* of OH_1_2R; an underground three-conductor 1/0A cable will have a *LineCableID* of UG_3_1/0A.

After reading the GIS data into MATLAB, the line type (OH or UG), number of conductors, and conductor code are known for each line/cable. Thus a *LineCableID* is created according the above naming rule for each line/cable.

3.2.6 Add Equipment Devices to the Network

At this step, equipment devices, such as transformers, spot loads, PV generators, capacitor banks, and switches, are added to the network.

3.2.6.1 Adding transformers, spot loads, and PV generators

Currently the GIS data of the secondary feeders are not available, and the loads and PV generators on a secondary feeder are aggregated as one spot load and one PV generator attached to the secondary side of their serving distribution transformer.

There are a total of 921 distribution transformers on the Sandvig 04 feeder, of which 33 are three-phase transformers (including locations where there are three single-phase transformers connected to a three phase line). Each record in the *TransformerUnit* table in the GIS data is assumed to be a transformer unit. For example, if a record has a PHASE field value of “ABC” and a KVA field value of 750 kVA, it is considered as one three-phase transformer unit with a total three-phase rating of 750 kVA. In CYMDIST, it is modeled as a three-phase transformer. On the other hand, if three records in the TransformerUnit table have the same OPERATINGNUMBER and have PHASE field values of “A”, “B”, and “C”, respectively, they are considered as three single-phase units operating as a three-phase transformer. Correspondingly, in the CYMDIST model, they are modeled as three separate single-phase transformers, each installed in its corresponding phase. However, in CYMDIST, if two or three single-phase units at the same location are identical, they can be grouped and represented as a multiple phase section. Nonetheless, on this feeder, there are 8 transformers consisting of two or three single-phase units that have different kVA ratings, and thus for these transformers each different single-phase unit is represented using its own section²⁷.

The operating number of a transformer is unique and is utilized as the *Device Number* in the CYMDIST model so that it can be easily identified in CYMDIST. For those 8 transformers consisting of two or three single-phase units that have different kVA ratings and thus are represented using multiple sections, their *Device Number* has a format of <Operating number>_<Phase configuration>, such as X521433_B. The kVA rating and low side voltage of the transformer is used as the *EqID* in the CYMDIST model to link this transformer to its specifications defined in the equipment library.

To place a transformer and its load and PV generator on the one-line diagram, first, the node to which the transformer’s primary is connected is identified using its coordinates from the GIS data. Then the orientation of the transformer’s symbol on the one-line diagram is decided such that the transformer is in the middle of the largest of the angles formed by all the lines connected to the node at its primary. This way the chance that the transformer’s symbol overlaps the lines is minimized. This is illustrated in Figure 28, which shows part of the final CYMDIST one-line diagram after the model is created in CYMDIST.

²⁷ In CYMDIST, a section is basically a two-dimensional placeholder to which equipment devices can be attached. It has a *from node* and an *end node*. It also specifies the phase configuration for all devices attached to it.

The spot load and the PV generator (if existing) are connected to the secondary node of the transformer, as seen in Figure 28. The load symbol is in the same direction as the transformer, while the PV generator is perpendicular to them, as shown in Figure 28.

Figure 28. One-line diagram showing transformers and their spot loads and PV generators

Both the load and the PV generator (if existing) use their transformer's operating number as their *Device Number* in order to easily identify them in CYMDIST.

The active and reactive power of the loads can be specified here through the CYMDIST graphical user interface using the results of load data processing discussed in Section 4. However, one can also specify the load data after the model has been created in CYMDIST using the COM interface provided by CYMDIST.

3.2.6.2 Adding Capacitor Banks

There are three capacitor banks on the Sandvig 04 feeder. The process of adding a capacitor bank to the network is similar to that of adding a transformer. First, the node to which the capacitor bank is connected is identified using its coordinates from the GIS data. Then the orientation of the capacitor bank's symbol on the one-line diagram is decided such that the chance that the capacitor bank's symbol overlaps the lines is minimized. Figure 29 shows part of the final CYMDIST one-line diagram after the model is created in CYMDIST.

Figure 29. One-line diagram showing a capacitor bank

When adding a capacitor bank to the network, its *EqID* is determined using its rating (available from the GIS data) so that its basic parameters can be located from the CYMDIST equipment library. In addition to these basic parameters common to all capacitor banks of its type, there is a parameter specific to a given capacitor bank: its control type and corresponding on/off thresholds.

3.2.6.3 Adding Switches

There are in all 18 switches on the Sandvig 04 feeder. As with transformers and capacitor banks, switches are a point type feature class in the GIS data. The node to which a switch connects can be easily identified from its coordinates. However, a switch is a series component and thus the distribution line section to which the switch attaches also needs to be identified since a node is generally connected to two or more lines. Since no specific information was available from the GIS data to determine this, the switches were attached to the first section the MATLAB program found that had the same phase configuration as the switch.

The information for the switch nominal and current status is available from the GIS data and modeled in CYMDIST. Figure 30 shows a switch in the CYMDIST one-line diagram.

Figure 30. A switch in the CYMDIST one-line diagram.

3.2.7 Writing to Text Files and Importing into CYMDIST

Completion of all the above data processing steps resulted in the network model being fully defined in MATLAB. To transfer the network model to CYMDIST, the model data were written into two text files in a format specified by CYMDIST [5], one for the network, the other for the loads. These files were then imported into CYMDIST. A screenshot of the importing process and a sample text file for the network are shown in Figure 31.

After importing the text files into CYMDIST, the model was created. Figure 32 shows the one-line diagram of the resulting model, together with the original GIS figure for a comparison. In the CYMDIST diagram, black lines indicate three phase network; red, green, and blue lines indicate phase A, B, and C networks, respectively. Figure 33 gives a detailed view of part of the system. The team verified that the CYMDIST one-line diagram matched the GIS plot visually.

Figure 31. CYMDIST text file import window and a sample network text file

Figure 32 Comparison of the CYMDIST diagram with the GIS plot.

Figure 33 GIS plot and CYMDIST diagram comparison. Blue dots on the GIS diagram indicate transformer location.

4 Load and Solar Resource Development

Detailed models of certain types of loads become essential for studying the impact of high penetration PV on power quality, control stability and operation of distribution systems. Features of interest related to load modeling include load coincidence factor with PV generation, response to voltage flicker introduced by the dynamic variation in PV output, and other power quality interactions between customer loads and PV inverters.

The purpose of load analysis is to develop detailed understanding of spatial and temporal load distribution on Sandvig 04 feeder. The results of the analysis can then be used to create statistically representative load profiles and apply them to study resulting voltage profiles on the feeder as a function of location and time. Accurately predicting spatial distribution of load is a complex problem and was further complicated by absence of direct measurements that would enable validation of calculated values. The methodology starts from the data sources that are typically available to the utilities, and employs the custom-designed analysis methodology to estimate the loading of every distribution transformer at any point in time. These estimates are then used to assign the loading of every transformer and this enables spatially accurate load allocation, based on transformer locations recorded in the GIS database.

Once the temporal and spatial distribution of load is known, it becomes possible to apply similarly estimated temporal and spatial distribution of power generated by PV and compute the voltage profile on the studied feeder at any desired level of PV penetration. This is useful as it enables fair and systematic assessment of feeder's capability to accept PV, and enables informed design of upgrades to accommodate higher penetration if desired.

The analysis starts by separating historical load data into day of week, seasonal, and time of day. A comprehensive statistical analysis is then performed on these sub-groups. This provides insight into load patterns and their variations, and provides corresponding probability density functions for any given hour of any representative day. The inputs to this part of the analysis are measured load curves for a specific customer class. The outputs are probability density functions for every hour of a weekday or a weekend in any given season. For example, there is a probability density function for hour 10 of a summer weekday that is different from the probability density function of hour 11 for the same day, and different from the one representing hour 10 of a weekday in fall.

The probability density functions are described by gamma distribution functions with shape parameters and scale parameters identified based on historical data. The extracted distribution functions are then applied to generate feeder load and customer loads for multi-scenario study by Monte-Carlo method.

The following sections describe the analysis approach that extracts statistical information based on measured loads and define the methodology used to create representative loading patterns.

Key accomplishments for this task are as follows:

- Developed statistical load models to allow time series analysis of the feeder.

- Developed solar resource models suitable for analysis of high penetration PV scenarios.

4.1 Overview of the Feeder load

The load data used as inputs to this study are listed in Table 3. Starting at row 1 there is “SV04” representing total feeder load sampled at one-hour averages and includes active power (P), reactive power (Q), and voltage magnitude (V). Such records are typically available from EMS databases (where EMS stands for Energy Management System). The remaining rows document sources of data from load research. These are collected with either hourly or 15-minute intervals and normally include only active (real) power. To ensure consistency, the load profiles were examined at hourly intervals. Therefore, data files recorded at 15 minutes intervals were averaged over four samples to represent the load of a given hour.

Table 4 Load Data Outlines

Load Name	Load Type	Time Period	Sample Rate	P	Q	V
SV 04	Feeder Load	01/01/2009 - 12/31/2009	1 hour	Y	Y	Y
100_K26352	E-12 - (Standard Residential Rate)	01/01/2009 - 12/31/2009	1 hour	Y	N	N
120_J89390	Time Advantage 9-9 (Frozen)	01/03/2008 - 01/02/2009	15 minutes	Y	N	N
300_L86277	Commercial/Industrial	01/03/2008 - 01/02/2009	15 minutes	Y	N	N
320_661131	E-32 - (General Service)	01/03/2008 - 01/02/2009	15 minutes	Y	N	N
3500_D28792	E-35 TOU - (Extra Large Service Time of Use)	01/03/2008 - 01/02/2009	15 minutes	Y	N	N
4300_P75825	Time Advantage 7pm – noon	02/19/2009 - 02/18/2010	15 minutes	Y	N	N
4800_P75863	E-32, E20, E-221, various (Commercial)	02/12/2009 - 02/11/2010	15 minutes	Y	N	N
4900_P75976	Time Advantage	02/05/2009 - 02/04/2010	15 minutes	Y	N	N

4.2 High-Level Overview of Load Allocation Process

The process map of the load allocation process is shown in Figure 34.

The first step in the load separation and allocation process is the analysis of historical data to remove “bad” data. The resulting output data is then examined by visualization tools to glean insight into seasonal patterns and resulting variability. This step provides a simple but effective checkpoint that can detect errors in the pre-processing scripts and adjust them for a more refined elimination of errors or outliers. The visualization is also used to quantify hourly variability by estimating and plotting averages and one-sigma tolerances of hourly load patterns.

Figure 34 Load Separation and Allocation – Process Map

The next step is the statistical analysis that delivers probability density functions (.pdfs) for any specific load hour of any specific customer class. There are 24 pdfs for each of eight typical days: a weekday and a weekend for each of the four seasons. The probability density functions are then supplied to the Monte Carlo simulations and used to generate hourly load curves. These curves are subsequently scaled based on the individual customer's billing data to generate temporal load profiles for every metered customer. Finally, the profiles are aggregated by transformers that serve them and tabulated for direct application in the load flow model.

An additional refinement pass is made on generated time series that applies rolling average filtering over six consecutive samples. This has the effect of applying autocorrelation to the load time-series and it thus softens the sample-to-sample variations that arise as a consequence of independent sampling at every hour.

4.3 Load Separation and Visualization

As was discussed, historical load is separated by season and by day of the week and further grouped by hour of the day. As a result, hourly load samples are organized into groups corresponding to each hour of any typical day. These samples are used to calculate the mean value and standard deviation for every group. Three types of figures are used to illustrate load patterns. Using seasonal separation as an illustration, the plots are as follows:

- 24-hour load curves for each season
- average load curves for each season
- whisker plots for each season.

The 24-hour load curves show the overall range of load and help visualize variability in the raw data. The average load curves provide the hourly patterns representative of the season, and are much smoother than the original load curves. Finally, the whisker plot shows the statistical properties of the load at each hour. The next few sections illustrate this process and show some of the resulting plots.

4.4 Data Preconditioning

The historical load data used for the study covers actual measurements from Sandvig04 for 2008 and 2009. The total feeder load for 2009 is shown in Figure 35.

Figure 35 Raw Data of Feeder Load

The source data files also include a quality-type flag used by APS to record confidence in the corresponding data measurement. A quality-type flag in the data indicated if the data was true data or some type of estimated or invalid data. For the year of 2009, 96.37% feeder load data are true data.

The pre-processing eliminates some samples based on the quality-type flag, and makes additional rudimentary checks to eliminate outliers. With respect to load curve in Figure 35, zero values after hour 8,000 were eliminated along with several other samples (e.g. zeros near hour 700, high values near 7,400, and some of the transiently high values around the zero period starting at 8,000).

4.5 Estimating Probability Density Functions

Based on the shape of the histograms coming from pre-processing, a gamma distribution was used to fit the load distribution. The gamma distribution is a two-parameter family of continuous probability distributions. The gamma distribution probability density function is given by:

$$y = f(x; a, b) = \frac{1}{b^a \Gamma(a)} x^{a-1} e^{-\frac{x}{b}} \quad (1)$$

where, a is shape parameter and b is scale parameter.

Figure 36 shows the original histogram and the gamma distribution fit for the valid samples of feeder load over the entire year. The calculated shape and scale parameter are 31.46 and 0.13 respectively.

Figure 36 Distribution of Valid Feeder Load without Outliers

4.6 Daily Load Profiles

Figure 37 illustrates the 24-hour load curves across all seasons. Weekday plots show historical data in red, and the hourly means and $\pm$ one standard deviation curves in green. The colors are inverted for weekend plots.

Figure 37 24-hour Load Curves by Separated Day of Week

Figure 38 Mean Value Load Curves Separated by Day of week

The average value plots are then shown in Figure 38 to illustrate the trends by day of the week. The weekday traces show two local peaks: one at 8AM and another at 8PM. For weekends, the morning peak hour shifts to 10AM and the morning load rise is slower. Evening peak hour remains at 8PM. Load on Friday and Saturday evenings is lower than on other days; possibly a result of residential customers spending time outside of their homes on those two days.

Figure 39 shows the whisker plots of daily load to illustrate the overall range of data and one-sigma regions. Plots are slightly staggered horizontally to provide visual separation between days.

Figure 39 Whisker Plots of Load Separated by Day of Week

Figure 40 24-hour Load Curves Separated by Season

Figure 41 Average Load Curves Separated by Season

Figure 42 Whisker Plot of Load Separated by Season

4.7 Seasonal Load Profiles

In addition to its daily patterns, load also exhibits seasonal patterns. As in the case of daily patterns, findings are illustrated using total feeder load.

The season start days for 2009 were defined based on data posted by US Naval Observatory, as follows:

- Spring: March 20th 7:44 A.M. EDT 1144 UTC
- Summer: June 21st 1:45 A.M. EDT 0545 UTC
- Fall: September 22nd 5:18 P.M. EDT 2118 UTC
- Winter: December 21st 12:47 P.M. EST 1747 UTC

Figure 40 - Figure 42 illustrate the 24-hour curves, the average curves, and the whisker plots for load data grouped by seasons. The average value plots show the two-peak load pattern for each season except summer. The notable increase in summer averages during early afternoon may be due to air conditioning load. Average winter load is consistently higher than load in other seasons, possibly due to heating load. The peak load of the feeder happens on a winter evening around 8PM. The minimum load is around 4AM (as would be expected,) but the spring load remains relatively light during most of the sunlight hours. From the standpoint of PV integration, this is an important time interval as the PV production will be at its highest in cool and sunny weather typical of spring mornings.

4.8 Final Load Separation for Statistical Analysis

Based on the insights from daily and seasonal analyses, load profiles were separated by seasons and further by weekday and weekend. This was arbitrarily dubbed “sub-seasonal” analysis and the resulting plots are shown in Figure 43 through Figure 46.

Figure 43 24-hour Load Curves Separated by Sub-season

Figure 44 Average Load Curves Separated by Sub-season

Figure 45 Whisker Plots Separated by Sub-season

4.9 Resulting Probability Density Functions

The parameters of Gamma distributions for each hour of eight typical days are listed in Table 5 and Table 6. Graphical representations of sub-seasonal probability density functions for total feeder load are shown in Figure 46.

Figure 46 Estimated Distribution Functions – Sub-seasonal

Table 5 Gamma Distribution Shape Parameters

Hour	Spring Weekday	Spring Weekend	Summer Weekday	Summer Weekend	Fall Weekday	Fall Weekend	Winter Weekday	Winter Weekend
1	158.03	134.78	264.40	175.94	81.36	118.93	114.31	196.78
2	127.91	109.78	284.70	244.91	73.96	105.21	113.94	220.04
3	115.31	101.13	295.03	256.61	68.65	91.94	101.05	182.48
4	101.16	102.86	304.61	242.22	66.68	88.33	93.20	173.99
5	93.53	92.92	349.47	268.16	62.55	84.73	93.50	172.39
6	94.18	95.72	421.13	332.53	64.55	86.55	96.58	156.48
7	79.40	87.14	521.07	455.09	67.57	87.34	117.70	176.37
8	66.12	83.26	392.83	391.95	76.59	84.91	117.22	176.27
9	111.36	110.33	598.11	339.44	87.82	98.56	114.05	185.33
10	210.03	143.71	519.76	283.60	90.72	114.63	134.42	224.99
11	278.06	197.39	310.15	195.09	101.73	124.36	136.29	223.78
12	381.49	210.80	188.99	144.86	122.37	135.91	124.84	192.96
13	452.98	241.10	144.15	124.61	146.93	143.77	123.77	150.62
14	458.75	265.00	107.69	99.06	193.00	134.15	130.57	131.87
15	420.00	272.80	99.55	88.86	264.62	138.69	135.71	121.87
16	426.45	250.27	93.39	95.21	320.86	134.15	126.14	103.53
17	369.43	238.87	89.38	96.01	364.47	138.03	123.98	81.92
18	315.69	218.94	90.78	98.42	267.74	125.11	115.39	76.67
19	219.22	198.34	107.17	110.43	108.95	84.28	84.25	67.87
20	191.95	147.86	158.65	162.08	121.11	91.64	78.30	80.21
21	150.85	110.93	223.90	174.17	158.95	107.48	129.13	125.76
22	224.63	164.70	284.84	170.91	144.58	100.68	147.13	140.70
23	218.10	180.47	272.37	192.16	130.47	102.86	140.63	169.24
24	223.71	179.69	232.41	230.49	117.20	101.84	118.52	211.38

Table 6 Gamma Distribution Scale Parameters

Hour	Spring Weekday	Spring Weekend	Summer Weekday	Summer Weekend	Fall Weekday	Fall Weekend	Winter Weekday	Winter Weekend
1	0.0208	0.0256	0.0128	0.0196	0.0429	0.0295	0.0362	0.0217
2	0.0240	0.0293	0.0109	0.0130	0.0443	0.0310	0.0343	0.0183
3	0.0260	0.0310	0.0103	0.0120	0.0463	0.0342	0.0380	0.0215
4	0.0294	0.0301	0.0098	0.0124	0.0472	0.0350	0.0409	0.0222
5	0.0320	0.0333	0.0084	0.0110	0.0506	0.0363	0.0410	0.0223
6	0.0331	0.0329	0.0073	0.0090	0.0513	0.0364	0.0410	0.0249
7	0.0428	0.0371	0.0063	0.0067	0.0538	0.0371	0.0368	0.0229
8	0.0586	0.0413	0.0093	0.0082	0.0550	0.0416	0.0429	0.0243
9	0.0354	0.0337	0.0064	0.0104	0.0486	0.0388	0.0444	0.0249
10	0.0181	0.0275	0.0075	0.0137	0.0443	0.0353	0.0351	0.0217
11	0.0133	0.0204	0.0128	0.0210	0.0380	0.0330	0.0329	0.0220
12	0.0096	0.0189	0.0216	0.0291	0.0308	0.0298	0.0345	0.0249
13	0.0080	0.0162	0.0289	0.0344	0.0250	0.0276	0.0336	0.0307
14	0.0078	0.0145	0.0390	0.0437	0.0187	0.0292	0.0312	0.0340
15	0.0085	0.0139	0.0428	0.0488	0.0135	0.0278	0.0295	0.0358
16	0.0084	0.0151	0.0463	0.0458	0.0111	0.0287	0.0314	0.0418
17	0.0098	0.0158	0.0489	0.0455	0.0099	0.0283	0.0323	0.0532
18	0.0119	0.0177	0.0493	0.0454	0.0142	0.0327	0.0362	0.0583
19	0.0179	0.0203	0.0422	0.0409	0.0389	0.0531	0.0551	0.0716
20	0.0216	0.0285	0.0290	0.0282	0.0393	0.0528	0.0685	0.0673
21	0.0297	0.0407	0.0213	0.0268	0.0306	0.0453	0.0431	0.0439
22	0.0203	0.0279	0.0169	0.0274	0.0326	0.0464	0.0369	0.0382
23	0.0196	0.0241	0.0162	0.0228	0.0334	0.0422	0.0365	0.0303
24	0.0168	0.0216	0.0168	0.0169	0.0334	0.0383	0.0387	0.0220

4.10 Monte Carlo Sampling

The one-year hourly feeder load can now be generated using the calculated probability density functions. As was mentioned before, time series data coming from Monte Carlo simulations are averaged over 6 consecutive samples to apply an effect of autocorrelation.

Figure 47 Feeder Load Histogram

The histogram plots of historical load and its sampled equivalent are compared in Figure 47. The mean value and standard deviation of the two load profiles have no significant difference.

The temporal correlation of Monte Carlo sampled load and historical load was also evaluated. Assuming that $x(t)$ and $y(t)$ are two time series signals, their correlation coefficient $R(x,y)$ is given as:

$$R(x,y) = \frac{\int x(t)y(t)dt}{\sqrt{\int x^2(t)dt \int y^2(t)dt}}$$

The resulting correlation coefficient between the simulated and historical load equals 0.93 – indicative of significant correlation.

$$R(\text{Simulated Load, Historical Load}) = 0.93$$

4.11 Allocation of Transformer Loads Based on Load Research and Billing Data

The load research data was processed in an analogous fashion and the corresponding “sub seasonal” probability density functions were assigned to each customer class. However, in this case, the load generated by Monte Carlo sampling has to be scaled using the information from billing data. Billing database provides information on monthly energy consumptions of all metered customers and this information was handled separately to define the scaling factors

between Monte Carlo generated time varying power consumption for any given month and the billing data.

Mathematically, this process can be defined as follows.

- **Inputs:**

P values at feeder head, labeled as $P'_{fh}(t)$

Monthly energy consumption profiles for all spot loads: E_k

Load research data – $P_k(t)$ samples, identified by rate code. Preprocessed to determine statistical distributions for each rate code.

- **Active power allocation**

Hourly distribution functions for customers in the given rate codes are all individually scaled based on their actual energy consumption. This is done by taking a random sample of total feeder load $P'_{fh}(t)$ and calculating the scaling factor $S_k(t)$, per (2).

$$S_k(t) = \frac{E_k}{\sum_{k=1}^N E_k} \cdot P'_{fh}(t) \quad (2)$$

Essentially, $S_k(t)$ is the expected power from k-the load at time interval “t”. The allocated load $P_k(t)$ is then determined by Monte Carlo sampling of the scaled gamma function, per (3). The scaling (represented in (3) by shape and scale factors $a(S_k(t))$ and $b(S_k(t))$), takes the original shape and scale factors determined from load research data and scales them to new values that result in expected value equal to $S_k(t)$.

$$P_k(t) = \Gamma(a(S_k(t)), b(S_k(t))) \quad (3)$$

Finally, after all loads on the feeder are aggregated, the sampled spot loads are scaled once again to match the total load at the feeder head.

$$P'_k(t) = \frac{P_k(t)}{\sum_{k=1}^N P_k(t)} \cdot P'_{fh}(t) \quad (4)$$

Energy consumption of loads with negative monthly records (perhaps arising from reimbursement for overestimating consumption in previous month(s)) is adjusted to 1/12 of the total consumption of the year.

If gamma distribution of a category of a load cannot be estimated because there is no historical data for that category, the energy consumption is used to scale the spot load per (5).

$$P_k(t) = Sm_k(t) \times P'_{fh}(t) \quad (5)$$

This approach was used to generate one-year of load data for 873 customers; The histograms of: one spot load, all spot loads combined, and the total feeder load are compared in Figure 48.

The effect of load coincidence is visible in comparison of Figure 48 (a) and (b). The ratio of standard deviation to expected value (σ/m) was used as a measure of uncertainty and the aggregated load has this ratio three times lower than the individual load. The comparison of Figure 48 (b) and (c) confirms the expected similarity of two different ways for generating the total load: as a sum of many smaller loads, and directly based on the hourly distribution functions.

4.12 Solar Production Forecasting

Data analysis similar to that used for load analysis was performed on modeled hourly solar generation data obtained from the solar installers (installers used PVWatts to generate the production forecasts), and the analysis was used to estimate the PV production of a “baseline” 2kW PV system planned for residential installations on Sandvig04. Unlike load, solar irradiation does not exhibit different patterns on weekends and weekdays, so only seasonal patterns are shown. The data analysis, labeling, and meaning of curves are analogous to those of load. The resulting 24-hour seasonal solar profiles are shown in Figure 49, their average values in Figure 50, and whisker plots in Figure 51.

These curves can now be used to generate multiple scenarios of solar production and overlay those predictions over load curves to come up with precise spatial and temporal distribution of “net-load” for Sandvig04. Some of the preliminary findings are discussed in Section 5.

- Single spot load ($m = 9.096\text{kW}$, $\sigma = 3.344\text{kW}$, $\sigma/m = 0.368$)

- Aggregation of all spot loads ($m = 4.07\text{MW}$, $\sigma = 0.59\text{MW}$, $\sigma/m = 0.145$)

(c) Total feeder load ($m = 3.9716\text{MW}$, $\sigma = 0.719\text{MW}$, $\sigma/m = 0.181$)

Figure 48 Histograms of individual and aggregated load

Figure 49 24-hour solar production curves separated by season

Figure 50 Average solar production curves separated by season

Figure 51 Whisker plots of solar forecast separated by season

4.13 Automation of Temporal Analysis

Load and solar profiles characterized in section 4 can be used to compute the steady-state voltage profile on Sandvig04 feeder and characterize it as a function of time. This enables characterization of the voltage range anywhere on the feeder and provides insight into expected number of operations of switched capacitor banks. The analysis marches the model through time and in each time step it performs load and solar allocation, solves the load flow, and reports converged results. The analysis needs to cover daily and seasonal variations of load and solar and also needs to include multiple scenarios for each interval to enable characterizing expectations with a desired statistical confidence. Accordingly, many simulation runs are needed and it becomes necessary to automate the analysis in order to make this type of analysis practical.

A custom program for this purpose was developed as a part of modeling effort. Visual Studio Express was used as a development platform and Visual Basic (VB) as the programming language. The tools are available for free from Microsoft. The VB program uses the CYMDIST solver for load flow computations and interacts with it using the Component Object Model (COM) module of CYMDIST. The high-level functional overview of the program is depicted in Figure 52. The inputs are the feeder model in CYMDIST format and the tabulated temporal load and solar profiles. The CYMDIST feeder model is loaded into memory using the 'Open Study' module. The load and solar data are loaded and pre-processed using the 'Prepare Data' module and conditioned for direct use by the 'Load Allocation' module. The Load Allocation routine then applies the load and solar data to CYMDIST model and passes control to 'Power Flow Analysis' module. Solved results are reported by the 'Reporting' module. The process of load allocation, power flow analysis, and reporting is then repeated for all load profiles in memory. All modules interface with CYMDIST engine through COM and use internal data structures of CYMDIST to hold the data and results for each run. VB holds the data for various scenarios and maintains several lists of indices that enable faster access to CYMDIST data structures and results.

Figure 52 Temporal analysis module

5 Preliminary modeling results

The model of Sandvig04 feeder is complete and can be run at any desired load level individually or via VB scripts. In order to validate the model, the teams studied the behavior of the model at several loading levels to detect notable excursions from expected feeder behavior.

This section presents some of the preliminary results to illustrate trends in the feeder's steady-state voltage performance and provide insight into qualitative and quantitative effects of high penetration PV deployment. The results are also providing a baseline for model validation – the model can predict voltage profile on the entire feeder at any loading level and this can be used to detect notable excursions from expected performance and define field measurements to be used for model validation. Validation is best served by predicting performance from a few distinct experiments defined by an easily observed set of conditions. In case of Sandvig04 the data with highest confidence is total feeder loading (from EMS) and the sample preliminary results discussed here are prepared based on high and low load levels representative of the month of January.

A representative load profile for January is shown in Figure 53. The maximum load occurs at hour 45 and minimum load at hour 149. The total load is around 6 MW for the 45th hour and

3.4MW for the 149th hour. These salient loading levels were further examined to illustrate the representative range of voltage profiles and flow of active and reactive power along the feeder.

Note that min and max aggregate feeder loadings aren't necessarily coincident with the most critical voltage excursions. A particular spatial distribution of load and PV could lead to some parts of the feeder having notable voltage excursions at times that do not correspond to times of min or max aggregate loading. Such circumstances can only be detected by running a comprehensive multi-scenario analysis, but this has no value before the models are fully validated.

Key accomplishments for this task are as follows:

- Performed simulations to assess initial modeling efforts
- Began model validation process by comparing model against field measurements

Figure 53 Estimation of Total kW Demand for the 1st Week of Jan 2009

5.1 Example Voltage Profiles and Reactive Power Flows

There are three power-factor correction capacitors on the feeder. In the CYMDIST model they were placed under automatic control and configured according to their actual settings. The resulting state of capacitors was that all three were in service at both the minimum and maximum load levels. However, since the capacitors have dominant impact on voltage profile, results were included with two configurations of capacitor banks: all three in, as the simulations predict, and all three out, to illustrate the range of voltage change with no reactive power compensation.

The diagrams in Figure 54 correspond to a sample of high winter load. The results are calculated using an unbalanced load flow algorithm, but post-processed to show positive-sequence voltage magnitude only. The positive-sequence voltage magnitude is shown in the upper half of the figure as a function of distance from the substation. The thickness of traces denotes the state of capacitors – thick for on, and thin for off. The corresponding three-phase reactive power flow (Q flow) through the feeder is plotted in the diagram on the bottom half of the figure.

The impact of reactive power compensation is apparent from these diagrams – supplying the reactive power along the length of the feeder reduces the total voltage drop. This aligns well with expectations and the analysis provides quantification of expected voltage drop and enables confirmation by field measurements.

The diagrams in Figure 55 represent the light load condition. The overall voltage drop is lower compared to that of Figure 54 and there is negative reactive power (Q) flow at the feeder head.

5.2 Model Validation

The load allocation process relies on data from multiple utility databases – in this case those are: EMS, GIS, and billing. Furthermore, it depends on information that is not used in every day utility workflows. For example, billing database identifies a transformer that serves the customer load. A normal billing workflow does not depend on accuracy of that record – as long as the kWh readings and the mailing address are correct, the transformer entry could be wrong without any impact on the billing process and go undetected for years. Similarly, the GIS database reports the type of transformer installed at a certain location, but the only useful case where this information is relied on is transformer replacement. Assuming a transformer service life of well over twenty years, it is clear that the likelihood of detecting the error is small. Furthermore, records showing phase information for any single-phase transformer could be inaccurate and this would not get picked up without a special inquiry needing a specialized measurement tool.

It follows that the modeling process has to account for these uncertainties in data sources, yet deliver models with appropriate fidelity to answer the key questions of the study. In addition, in order to be practical, the modeling process has to rely on automated data processing and, to the degree possible, automated error detection. Many automated crosschecks are possible and they require different complexity of implementation or human interaction. Generally speaking, increased processing complexity, increased number of available measurements, and a commitment to engage operators all yield increased entitlement for error detection, and since the processes can largely be automated, there is an opportunity to develop sophisticated tools to address this need. In this phase of the project, efforts were limited to a few relatively simple crosschecks that were described using the model as the example case.

A simple and very effective crosscheck is to compare transformer rating in the model with a connected load during various loading levels. The test can be fully automated and the most notable overloads can be readily reported. Sample results of this screening applied to the model are shown in Table 7.

Clearly, there are data problems with the top three units and very likely problems with the following two. APS checked the underlying data and found errors in records reporting connected load. These errors had a significant impact on voltage imbalance because they effectively

assigned inordinately large single-phase loads to the actual transformers. The plots of voltage profile before and after correcting the load data errors are shown in Figure 56.

Figure 54 Voltage and VAr Profiles as Function of Distance – High Load

Figure 55 Voltage and VAr profiles as function of distance – low load

Table 7 List of overloaded transformers at ~5MW feeder load

Equipment No	VA (V)	VB (V)	VC (V)	Thru Power A (kW)	Thru Power B (kW)	Thru Power C (kW)	Cap Nom (kVA)	Thru Power (KVA)	% of Overloading
N4495	95.786			367.984			50	442.2	884%
N4491		111.991			237.598		50	277.3	555%
X338860			114.963			23.423	10	32.8	328%
N23313	113.444			27.812			25	34.4	138%
X338859			121.376			11.141	10	12.6	126%

The improvement in the imbalance is significant and although it cannot be claimed that the model has absolute accuracy, the improvement is evident.

To further validate the model, APS performed the field measurement of feeder voltages at several locations along the feeder. The total feeder load at the time of measurements was captured from EMS and the model was configured to the same load level. The measurements were made at the secondaries of three-phase transformers and thus depend on overall voltage profile and the voltage drop across the transformer. These results were compared with the model predictions from the same secondaries. Figure 57 documents the locations of transformers and Figure 58 and Figure 59 the voltage discrepancy between the model and measurements.

Figure 58 and Figure 59 compare the modeling results to results from field measurements. Let V_{1a} , V_{1b} , and V_{1c} denote the magnitudes of line to neutral voltage obtained from the model, and V_{2a} , V_{2b} , and V_{2c} the measured values. Furthermore, let V_{1avg} denote $(V_{1a}+V_{1b}+V_{1c})/3$ and V_{2avg} the analogously computed average of measured voltages. The results in Figure 58 represent the percentage error of average magnitude: $(V_{1avg}-V_{2avg})/V_{2avg}*100\%$, and the values in Figure 59 compare the percentage imbalance of phase voltages for measurements and model. Measurement results are shown in the left with values defined as: $(V_{2a}-V_{2avg})/V_{2avg}*100\%$ and modeling results are shown in the right with values defined as: $(V_{1a}-V_{1avg})/V_{1avg}*100\%$. Both sets include results from all three phases with analogous definitions.

Figure 56 Voltage profiles before and after correcting load data errors

Figure 57 Measurement locations for model validation

Figure 58 Percent voltage error, 3-phase average, model vs. measured

Figure 59 Percent voltage imbalance, model vs. measured

The voltage levels predicted by the model are within a few percent of measured values and the percent imbalance between model and measurements is comparable. Based on this assessment, the model has adequate accuracy to be used for further analysis.

5.3 Effect of Solar Production on Voltage Profile

Effects of solar production on the voltage profile of Sandvig 04 were studied by introducing the planned 1.5MW of distributed PV to the model as point sources of power, set to unity power factor. The planned 1.5MW of distributed PV is made up of: 500-700kW utility owned installation at Doney Park, the 400kW commercial installation at Cromer Elementary, and the remaining 400-600kW of residential installations distributed throughout the Sandvig 04 service area. The yellow stars in Figure 60 denote the two larger installation sites (Doney Park is further to the North.) The model included the two larger installations at their specific locations, and

assigned the balance of PV capacity by randomly choosing their location from the set of load buses.

The analysis was performed at a loading level representative of light winter load. As before, the reactive power compensation capacitors were configured to operate according to their actual settings, and this resulted in all three banks being in service. The resulting voltage profiles with and without PV injection are shown in Figure 61. The thick lines represent the state without PV generation and thin lines with 1.5MW of PV. In contrast to reactive power flows discussed earlier, the figure shows the active power flow on the right hand side. The contributions of large PV installations is apparent from the plots, the Doney Park inverter offsets approximately 600kW near 6.2mi, while the Cromer Elementary offsets another 400kW near 4mi. Careful inspection of power flow diagram indicates a small reversal of power flow near Doney Park site. This highlights the need to study effects of high PV penetration both temporally and spatially – in this case the specific spatial allocation leads to the penetration level higher than 100% at the northernmost part of the feeder. While this will not cause voltage problems in this case, it is a condition that would be overlooked by limiting the analysis only to comparison of aggregate loading and PV production.

Figure 60 Installation sites of utility and commercial inverters

Figure 61 Voltage profile w/ and w/o PV

6 Data Acquisition

During Phase 1, a data acquisition context was developed to support the entire project. The requirements include not only the capture of data artifacts required to validate models developed during the course of study but also requirements for managing and maintaining the deployed data acquisition hardware and the PV systems for the duration of the study and beyond.

Key accomplishments for this task are as follows:

- Developed data acquisitions context for the project
- Developed weather station prototype, constructed and installed at APS STAR
- Developed customer-sited PV generation data acquisition prototype, constructed and installed at APS STAR
- Developed communications methodology for data acquisitions for weather and PV in the project area, constructed working prototype at APS STAR

6.1 Data Acquisition Context

The Flagstaff demonstration is designed to answer several core questions related to high penetration scenarios. The core questions revolve around technical impacts but also include operational or deployment questions that may provide insight into the structure and methodology for future high PV penetration demonstrations. The data acquisitions context revolves around gathering data on the following:

- Environmental parameters (at sufficient locations to “characterize” project area)
- Feeder total load, electrical characteristics, and response to environmental and PV events (along the entire length of the feeder, at sufficient resolution to be “meaningful” to the analysis)
- Feeder device load, electrical characteristics, and response to grid events
- PV system inverter output production, electrical characteristics, and response to environmental and grid events (at sufficient locations and resolution as to be “meaningful” to the analysis)
- Customer load data (at sufficient locations as to be “meaningful”. For this project, AMI makes it possible to collect this for every customer)

6.2 Data Acquisition Platform and Methodology Considerations

Study Requirements

An initial set of data requirements for steady state analysis was developed. Some of the data, especially from the feeder head was available from existing data sources. Looking forward to future phases of the project, team members have recognized that study data requirements may change or need modification over the course of the study. Project team members need direct access to not only the data acquisition configuration but also the data. In addition, the subsequent phases of the project, which address dynamic analysis, require data sampling and recording rates that are much higher than currently available.

6.2.1 Field Data Acquisition and PV System Maintenance (O&M) Requirements

To ensure the high penetration PV capacity on the feeder, there is a need for owners of the PV system, in this case the utility, to have visibility into the performance of the PV systems so that poor performance or system faults can be identified as quickly as possible and corrective action taken. For such needs, day-behind, hourly reads are currently thought to be sufficient. In addition, any fielded hardware such as weather stations must be maintained over the course of the study. The data repository for all data must also be sufficiently robust and maintainable over the course of study and beyond. Information about the maintainability and reliability of the PV systems will also feed into the cost benefit analysis in future phases.

6.2.2 Grid Operator Requirements

There is a need for grid/feeder operations personnel to be aware of the KW contributed by PV at any given time so that adequate reserves are available in case the PV becomes unavailable due to PV system faults, environmental effects such as clouds or other operational factors. Exactly how to do this for hundreds of distributed residential-sized systems, or even whether it is necessary, has not yet been determined. It was however, deemed cost-prohibitive to install real-time energy production monitoring hardware on all residential PV installations. Therefore, only around 10% to 20% of the PV installations will be equipped with this real-time energy monitoring capability. PV generation data from the monitored systems will be aggregated, scaled to reflect the total number of PV systems deployed on the feeder, and then presented to the grid operators. For the grid operations needs, data must be delivered to the operations staff in as close to real-time as possible, with 1 to 10 sec being considered sufficiently close to “real-time” for normal operations. Project analysis will include a review of this methodology and will assess whether it met grid operational requirements or not.

Table 8 Data Acquisition Configuration

Measurement Type		Collection Platform	# Field Loc.	Data Interval	Data Availability	Data Points Collected (sample)	Analysis Supported
Environmental Parameters		CSI Data Loggers	6	1 sec	“real-time”	Solar irradiance, temperature, wind	Steady-State Model Validation, PV O&M, Grid Operations, Cost-Benefit
Customer Load		Elster REX2 AMI Meters	~3,000	60 min	day-behind	kWh	Steady-State Model Validation, Cost-Benefit
PV Inverter Generation	Data Stream 1	Elster REX2 AMI Meters	~120	15 min	day-behind	kWh	Steady-State Model Validation, PV O&M, Cost-Benefit
	Data Stream 2	SEL ²⁸ 734P Power Quality Meters	~22	1 sec	“real-time”	kWh, V, I, kVAr, harmonics, other PQ	Steady-State Model Validation, Grid Operations
Feeder Device Electrical Parameters		Feeder Reclosers	2	15 sec	“real-time”	I	Steady-State Model Validation, Grid Operations
Feeder Head (Substation) Electrical Parameters		Substation Relay	1	10 sec	“real-time”	kW, V, I, kVAr	Steady-State Model Validation, Grid Operations
Feeder Point Electrical Parameters	Data Stream 1	Power Quality Meters or Data Loggers	~ 6	1 sec	“real-time”	kWh, V, I, kVAr, harmonics, other PQ	Steady-State Model Validation, Cost-Benefit, Grid Operations
	Data Stream 2	Power Quality Meters or Data Loggers	~ 6	8 kHz	day-behind	kWh, V, I, kVAr, harmonics, other PQ	Dynamic Model Validation

6.3 Field Data Acquisition Deployment

6.3.1 AMI

AMI is currently deployed to almost the entire Flagstaff region (~36,000 customers). The study leverages this deployment to provide customer load and customer-sited PV generation data. Following are items to note regarding the AMI deployment:

- The configuration requires a second meter to be installed at the customer site to measure PV production.
- The physical installation required the development of a novel dual-meter socket adapter to allow for a utility side interconnection required for the study.

Utility AMI systems are generally configured to read 1 (demand) meter per site, and significant modification was required to update business processes and software to allow a second meter to be placed at a customer location.

6.3.2 Substation & Feeder Devices

Substation data is already being collected as part of APS's energy management system and will be leveraged to support the analysis.

6.3.2.1 Weather Station Prototype

A weather station prototype was constructed at the Solar Test and Research (STAR) center to prove design principle and provide a training station for field installation.

The weather station prototype consists of weather sensors mounted on a 1" rigid pipe upright. The sensors are wired to a Campbell Scientific (CSI) CR1000 data acquisition system. The weather data are sampled and stored at 1s interval. A GPS receiver is used to accurately set and maintain the system clock. A wireless radio network is used to create an Ethernet network for communication to the CR1000. Data are transferred to the APS network using the DNP3 protocol over TCP/IP.

CSI LI200X pyranometers are used to measure global horizontal (GHI) and south-latitude tilt (LATs) irradiance. A CSI HMP50 temperature and relative humidity probe is used to measure site temperature and relative humidity. A CSI CS106 barometer measures atmospheric pressure. A RM Young heated rain bucket is used to measure precipitation, including snowfall. A CSI wind sentry set is used to measure wind speed and direction.

Figure 62 Weather Station Prototype

Figure 63 Weather Station Prototype

The CR1000 is programmed to sample data every 1s. The calibration factors (multiplier and offset) of various sensors are programmed into the CR1000. The barometric pressure reading is refreshed every 15 min. Both raw data (mV, Hz, counts) and processed data are stored in a table every second.

Every second, the CR1000 receives a text string array from the GPS unit. This text array is parsed and time information is used to synchronize the data logger clock with the GPS clock. Time is only synchronized if adequate GPS signal is acquired.

Every second, the CR1000 updates a DNP3 slave table, which is read by a real-time automation controller and the data is fed into the APS “PI-historian” database.

Figure 64: Weather Station Data Acquisition Methodology

6.3.2.2 PV Generation DAS Prototype

A 4 kW photovoltaic (PV) system was installed on a mock-up roof at STAR. A customer premise ac DAS prototype was constructed at the STAR center to prove design principle and provide a training station for field installation.

The customer premise ac DAS prototype, at the basic level consists of an AMI meter that collects 15-min interval data for all PV generation sites. For a select number of installations, a Schweitzer Engineering Laboratories SEL-734 advanced metering system will collect additional information. The SEL-734 samples ac voltages and currents at a high sample rate, calculates, and

Figure 66 HPSD Customer Premise Data Acquisition System

Figure 67 Flagstaff Community Power PV System Examples

stores various power quality information. A wireless radio network is used to create an Ethernet network for communication to the SEL-734. Data are transferred to the APS network using the DNP3 protocol over TCP/IP. The SEL-734 time is synchronized to the APS network through the DNP3 protocol. The SEL power quality meter was chosen after considering a number of factors including the ability to interface to utility communications network and infrastructure, ability to capture information at desired speed and resolution, and ability to be integrated into utility processes for deployment and maintenance.

Data Acquisition Prototypes for Feeder Electrical Parameters

Figure 65: Customer-Sited Data Acquisitions Methodology

Electrical parameters relating to the distribution feeder will be collected via six utility pole-mounted power quality meters (Schweitzer Engineering Laboratories (SEL) power quality meter (SEL 735). The team explored multiple options prior to finalizing the platform and the final design leverages existing knowledge, infrastructure and processes for maintenance that will allow for a more seamless integration into utility operations for the duration of the study.

The core functionality of this set of data collection devices is that the power quality meters are enabled with cross-device triggering which will allow the project team to measure and record parameters from six separate locations along the feeder simultaneously. The data measurements can be scheduled to be taken automatically at a certain time, or they can be taken based on a user-defined “trigger”, such as a change in irradiance levels or change in electrical parameters at any of the locations. The device will operate in two modes, in “standard” mode, measurements will be taken every second, in “high bandwidth” mode, the measurements will be taken at a very fast rate (thousands of measurements every second) to ensure that as many fluctuations in grid parameters as possible are captured.

The primary measurement device, the SEL 735, was not commercially available as of June 30, 2011 and therefore, a full prototype was not built. Bench testing with a similar product, the SEL 734p, was conducted to assess the feasibility of the cross-device triggering and testing results showed that the functionality expected from the final platform should meet project specifications.

Figure 68: Feeder Data Acquisition Locations (Blue Stars)

Data Communication, Collection and Storage Methodology

Several months of work by a team of IT specialists was required to build connectivity between the various data collection and storage platforms that will provide information for the project. Data collection strategy leverages APS's existing AMI infrastructure and is supplemented by a network of wireless radios. Primary data storage is accomplished using an OSIsoft PI data

Figure 69: Feeder Data Acquisitions Methodology

historian. During the initial phase, the data historian required modifications to its time stamp configuration and also required modifications to its compression methodology. APS expects additional effort will be required to manage and store the various data streams as the project moves into the deployment phase.

7 Inverter Testing

The goal of the inverter testing during Phase 1 of the project was to prepare APS and GE for the deployment of the inverter at the Flagstaff site during Phase 2. Since the inverter has capabilities beyond what is specified in the UL1741/IEEE1547 standards, testing and characterization of the inverter at the STAR test site was seen as an important step in getting the inverter qualified for operation at Flagstaff. These advanced features and their application sparked discussions around current interconnection standards, potential benefits of advanced grid features and their application in high penetration scenarios.

During Phase I, the inverter was on lease to the project by GE and shipped to the STAR test site. This solar inverter was the first commercially available GE solar inverter to be deployed on a utility feeder. The inverter was unpacked and commissioned by GE and APS personnel, and communications established between the GE inverter/SCADA system and the GE Remote Operations Center. An acceptable layout including a load-bank and reverse-power-relay was designed to insure that power would not be transferred from the inverter to the APS grid during the initial testing phases. This was done to allow APS personnel to become comfortable with the operation of the inverter before using it to deliver power to the APS grid. Once this setup was complete and connected to the satisfaction of both APS and GE, reduced-power testing of the inverter began. Due to dc power limitations at STAR, the inverter output power for testing at STAR was limited to approximately 10% of the inverter's rated power.

Testing resulted in data showing inverter operation on both cloudy and sunny days. Due to the capabilities of the inverter's data-logging system, the project team has stored a significant amount of data to be used to for analysis in Phase 2.

APS, like other utilities, has several major concerns when dealing with the installation of power generating equipment connected to their system. These concerns fall into three major categories: the safety of utility personnel and customers, the prevention of damage to the utility system, and the prevention of problems for other utility customers and equipment. Modern solar inverters must function not only to deliver power from the solar panels to the grid, but must act to control the delivery of that power in such a manner as to address the concerns of the utility operating the grid. Some important considerations for grid interconnection include the following:

- Protection in loss of utility situations (anti-islanding feature)
- Protection against possible backfeed into a supply authority system fault
- Output under/over voltage protection
- Under/over frequency protection
- Harmonics and DC injection protection.

Today these requirements have to be met in such a way as to also prevent/mitigate issues associated with a locally high-penetration of PV. One of the more pressing issues associated with locally high-penetrations of PV is voltage fluctuation. These issues are well-known and have been well-documented in the industry.

An anticipated solution to this problem that will be of relatively low-cost to inverter manufacturers and utilities is the addition of the capability of solar inverters to provide reactive power to the grid for the purposes of providing voltage regulation. This issue is receiving a lot of attention today and the IEEE P1547.8 committee is actively working on recommended practices for advanced inverter functionality. Specific concerns over standards and inverter certification will be described in later sections.

Key accomplishments for this task are as follows:

- Performed real time simulation with PV inverter controls as hardware in the loop
- Successfully Installed PV inverter and SunIQ system at APS STAR facility
- Started high speed data acquisition and preliminary impact analysis

7.1 Lab Testing and Simulation

Lab testing and simulation was performed at the GE Power Electronics and Controls Center of Excellence and was used to support STAR. Although this testing did benefit the project, it was not done under DOE funding as it was considered to be broadly relevant to deployment of the GE solar inverter on utility distribution systems. The results of this lab testing and simulation were used to understand the anti-islanding behavior of the inverter and to explain to and show APS that the GE inverter exhibits behavior in accordance with the intent of UL1741 prior to its certification later in the year.

As a part of a separate GE-funded project focused on grid integration of GE solar inverters, GE Global Research has integrated the commercially available Real Time Digital Simulator (RTDS) platform with the GE Solar inverter controls platform hardware. The RTDS system is used by utilities and universities worldwide. It is also regarded as industrial benchmark hardware-in-the-loop simulation platform for the evaluation of power system protection devices and algorithms.

The RTDS system enables the simulation of PV arrays, inverter hardware and the power grid. The system's high speed digital and analogue input/output capabilities allow simulations to interact, in real time, with external control hardware, such as the GE Inverter control boards. In effect, the controls hardware cannot differentiate between a field installation and the simulated RTDS environment. Figure 70 shows the setup at the GE Global Research lab in Niskayuna, NY. This lab setup includes the RTDS and the GE 700kW solar inverter's main control cabinet. The control cabinet was produced at the GE Energy Controls and Power Electronics Center of Excellence in Salem, VA and is indistinguishable from the control cabinet from a functioning commercially available GE solar inverter.

Figure 70: RTDS (left) and GE Solar Inverter main control cabinet (right) at GE Global Research

The exchanges between the two cabinets are electrical signals corresponding to pulse width modulation (PWM) signals from the inverter control cabinet to the RTDS system and voltage and current waveforms from the RTDS system back to the inverter control cabinet. The inverter control cabinet PWM signals are used to gate, or turn on and off, the RTDS simulated power electronic switches. The switches are used to perform the duties of regulating the DC voltage of the inverter DC boost stage or synthesizing the AC output waveform of the inverter grid connected stage. Consequently, the gating action produces changes in DC and AC voltages and currents which need to be provided as feedback signals back to the inverter controls. The RTDS system provides these signals using digital to analog converters which transform the simulated variables to electrical signals providing the inverter control cabinet with voltage and current feedback every 1-2 μs depending on the complexity of the model being simulated.

The simulated model is divided into two sections which run in parallel, one denoted as Large Time Step and the other as Small Time Step. The main difference in the two is the speed at which the next update to the model variable is calculated. The large time step executes calculations at speeds around 25 μs for the existing model, while the small time step updates calculations as fast as 1-2 μs .

The inverter hardware, such as semiconductor switches, capacitors and inductors are all simulated in the small time step as high simulation fidelity is needed to accurately represent the PWM switching events, which take place in the low kHz range. Figure 71 is the schematic representation within RTDS of the inverter hardware, complete with step-up transformer to the left and a DC power source, to represent a field of PV panels, on the right.

Figure 71: Simulated Inverter Hardware w/ step-up transformer (left) and DC power source (right)

The currents and voltages calculated in the small time step are interfaced with the large time step. The large time step simulates the larger power systems and the connection of the simulated inverter hardware to the simulated power system. This provides engineers with a great deal of flexibility in creating transient event such as single phase faults or line-to-line faults and observer inverter control disconnect the inverter or attempt to ride through the event depending on if the inverter is configured as a UL1741 inverter or enabled with Low Voltage Ride Through (LVRT) respectively. Additionally, rigorous validation efforts are being undertaken to ensure that the RTDS simulated environment with inverter control as hardware in the loop is as accurate as possible when compared to field data. Figure 72 shows a comparison of inverter captured data during a UL1741 field test (left), and during the same event reenacted with RTDS.

Figure 72: GE Inverter UL1741 test waveforms - Left - Field Data / Right - RTDS

Furthermore, RTDS has the capability of simulating grid conditions or events too dangerous and/or costly to be reproduced in the lab or field test installations. RTDS simulations are quickly created, executed and if needed, repeated with precise accuracy.

The RTDS system was used in Phase I to investigate the anti-islanding behavior of the GE solar inverter. The GE team will leverage this platform to evaluate cases of interest on the APS feeder

in Flagstaff. A reduced order model of the APS distribution feeder is to be modeled within the RTDS simulation environment with power injection, from the GE solar inverter, at the exact location of the 500kW installation. This will allow testing of inverter robustness in response to transient events caused by nearby capacitor banks and voltage regulators. This testing is planned for early in Phase 2.

7.2 GE Solar Power Plant System

The GE Solar plant architecture, as seen in Figure 73, is composed of up to 50 individual 700kW or 1000kW inverters interfaced to a single compact SCADA platform. The output of each inverter is immediately stepped-up to medium voltage levels via individual step-up transformers. This increase to distribution level voltages allows solar plant developers to reduce cable costs and losses due to higher current flow at lower voltages.

Figure 73: GE Solar Power Plant Overview

To effectively control the entire plant as one generation source to a common point of interconnection with the grid, every inverter has a fiber optic link to the plant controller or SunIQ system. This plant controller monitors, via potential and current transformers, the power quality at the interconnection point with the power system and regulates all inverters in a fashion that achieves a utility desired behavior at this point. The solar plant operator must therefore only interact with the SunIQ system to program or achieve a variety of grid friendly functions.

Figure 74: GE Solar Power Plant Communication & IO Overview

All essential functions of the inverter and plant controls are regulated through a GE proprietary platform called Mark VIe. This microprocessor based architecture is also found in controls for large gas and steam turbine power generation equipment. The adaptation of large scale conventional generation control equipment to large scale renewable energy has produced a welcome familiarity amongst utilities, and this has also been seen during the commissioning of the GE solar inverter at STAR. Much of the positive feedback for this platform revolves around its cyber security robustness and uptime availability.

The inverter currently at the STAR site is not UL1741 certified. As this was a major operation & safety concern for APS, the inverter may be replaced for Phase 2 with a UL-certified model. During Phase 1, substantial effort was made to illustrate that the inverter at STAR is certified to UL508C and was designed to meet the intention of UL1741 with the exception of the ride-through and VAR support features, both of which had been disabled during commissioning at STAR. Although it was finally determined that a UL-certification will be required for initial operation at Doney Park, the team was able to run the inverter at STAR without UL certification after extensive technical discussions between APS and GE. Overcoming this hurdle at the STAR site will facilitate evaluation of some of the non-UL compliant features at the Flagstaff site. Data being collected at STAR during Phase 1 will be used with modeling and simulation in preparation for enabling the advanced features during Phase 2. Once the UL certified inverter is interconnected at Flagstaff, GE will assist APS in obtaining approval to enable advanced grid support features by providing test data specific to the configuration at Flagstaff.

7.2.1 SunIQ – Plant Level Management, Control and Data Acquisition

The GE SunIQ system, a solar plant-level controller, is on lease to the DOE project by GE Energy. The SunIQ system was manufactured at the GE Energy Power Conversion and Controls

Division in Salem, VA. The completed unit was shipped to the APS STAR test site in Tempe, AZ. The SunIQ system arrived in late June and was commissioned alongside the inverter in August, 2010. This system is a commercially available product sold by General Electric for utility-scale solar applications. The SunIQ system assists in data collection and transfer and also includes the control for GE's closed-loop voltage regulation system. Although in this case the SunIQ system is controlling only a single inverter, the system is capable of controlling the operation of up to 50 inverters. For the purposes of this study, the SunIQ system and inverter are assumed to form a single unified system.

Figure 75: SunIQ with open doors. I/O panel (left) SCADA, controller, & customer laptop (right)

The SunIQ system also offers secure remote access for controllability and various plant health and production reporting functions. Additionally it offers integration with utility distribution management systems (DMS) and database recording systems via industry standard digital and analogue interfaces as represented in Figure 74.

Prior to field testing, a number of interconnection challenges were faced at the STAR site. Some of the major challenges and their solutions are described in later sections.

Figure 76: SunIQ web HMI looking at inverter summary page

7.2.2 Inverter

Field testing at the STAR test site was initiated upon completion of inverter commissioning at STAR. This part of the project included inverter setup and data collection scheme configuration, dc-side characterization, standards compliance issues, inverter performance verification and validation at low-power, data collection and analysis, and other associated issues.

An inverter was manufactured at the GE Energy Power Conversion and Controls Division in Salem, VA. The completed unit was shipped to the APS STAR test site in Tempe, AZ. The inverter arrived in late June and was unpacked in August upon the signing of the project contract between APS and GE. This inverter is a commercially available product sold by GE for utility-scale solar applications.

While many of the features offered by a GE Solar plant are implemented in the SunIQ SCADA system, the inverter has several features important to this project including the following:

Low Voltage Ride Through: This feature was developed from the LVRT algorithm used in GE's 1.5MW Wind Turbine product. LVRT is also mandated in parts of Europe today and is expected to help maintain grid stability in high-penetration environments. The project team is working to ensure that data acquisition and data capture during Phase 2 is setup to capture any LVRT events that occur during operation of the inverter at the Doney Park site.

Capture buffers: The inverter has high-capacity internal capture buffers which allow the project team to collect high-fidelity data not only of bulk inverter parameters such as voltage, power, power factor, and current, but also of internal inverter control parameters. The ability to collect data about the internal operation of the inverter will allow enhanced analysis of inverter operation during both normal operation and grid-transients. This will provide insight into design and potential improvement of grid features such as ZVRT/LVRT which is rare and difficult to test in the lab. During Phase 1 the GE team designed and implemented capture buffers appropriate for this project.

Full P/Q capability: The GE inverter has the capability to operate at its full-rated capacity in both real and reactive power modes. The inverter can be operated at any requested amount of reactive power between zero and 700kVAr and any amount of real power between zero and full available

real power as long as the sum of requested real and reactive power do not exceed 700kVA. This capability can be used to test the use of power electronics to regulate local voltage. It is the intent of the project team to fully evaluate this capability in Phase 2 of the project.

Figure 77: APS STAR center electrical solar system layout

7.3 Installation

This section provides an overview and discussion of some of the issues encountered during the inverter installation at the APS STAR facility.

7.3.1 Grounding

Electrical projects both large and small require special attention to grounding. Furthermore, in the case of a solar power plant or distributed generation, different code requirements may apply depending on who owns the generation installation. When divided using a broad stroke, the National Electric Safety Code (NESC) covers aspects related to utility owned power generation and power distribution installations, whereas the National Electric Code (NEC) covers aspects related to service utility interconnection to premise wiring as well as electrical conductors and equipment in public and private buildings. For example, portions of the NEC code require that PV panel string voltages not exceed 600V and that either the positive or negative terminal be grounded. Furthermore, NEC and NESC discuss and have various options for grounding and bonding of separately derived AC systems, as is the case with all transformers with the exception of autotransformers.

The particular issue faced at the STAR site was that APS has a standard operating procedure to ground the neutral of any wye configured transformer primary or secondary. Therefore the onsite step-up transformer had the secondary neutral point grounded. This configuration applies grounds on both DC side and AC sides of the inverter which can cause circulating currents in the inverter and can force well protected inverters to trip. This is typically not a problem with

smaller inverters (<250kW), which often come with built-in transformers to isolate them from this second AC side ground.

Figure 78: Smaller inverter (approx. ≤250kW) with built-in isolation transformer

Transformers add cost and losses in efficiency; therefore, large scale inverter manufacturers are pushing for direct medium voltage step-up without additional isolation transformers. This practice is common with transmission connected wind power but is not as common with utility scale, distribution connected solar power plants.

Initially the GE inverter was planned on being interconnected directly to the STAR site 480/12.5kV step-up transformer. However, the step up transformer at STAR is powers a distribution panel serving many different electrical loads. Therefore, removing the inverter side ground on the transformer secondary wye was not a possibility. Unfortunately, with the transformer ground in place the GE inverter could not be operated since this would apply ground paths on both sides of the unit as seen in Figure 79. This double-ground configuration would allow short circuit current to flow through the anti-parallel diode in the individual AC side phase legs during the grid voltage's negative half-cycle. This short circuit path is illustrated by the red line in Figure 79.

For the interim testing phase at the APS STAR facility, a separate isolation transformer has been inserted in between the inverter and the site step up transformer. This secondary transformer could be either a wye-wye (with ungrounded neutral on the inverter side) or wye-delta configuration. The team was able to quickly locate a wye-delta configured isolation transformer and installed it on-site, as seen in Figure 80.

Figure 79: Short circuit path with a doubly grounded inverter

Figure 80: Current STAR installation, isolation transformer breaks the ground loop

Before the inverter could be operated, a calculation of the effective impedance seen by the inverter had to be performed. This calculation takes into consideration the short circuit impedance of the medium voltage connection and any additional component impedances (such as transformers) between the inverter and the medium voltage connection. If this impedance is too high, the inverter is effectively connected to the equivalent of a weak grid connection. A weak grid connection can impede reliable power export from the solar installation. An initial satisfactory calculation was performed when only the step-up transformer was being considered. However, with the additional isolation transformer, the calculation was performed again and resulted in a narrower margin. This margin, however, is still sufficient to operate and export power in a reliable manner.

The final utility scale installation in flagstaff will take advantage of the inverter's 480Vac output and connect directly to a medium voltage step-up transformer. Furthermore, by collocating the inverter and transformer within 25ft the inverter's AC circuit breaker enables use of the NEC 25ft secondary tap rule.

7.3.2 Medium Voltage Access for SunIQ Plant Level Control

Earlier sections of this report briefly discussed advanced features coordinated by SunIQ and executed by individual inverters according to signals from SunIQ's Solar Control algorithms. These algorithms use feedback information from voltage and current signals at the point of interconnection with the utility grid. Typically, these voltage and current signals are measured from the primary (high voltage) side of the step-up transformer. Unfortunately, access to the high voltage conductors wasn't readily available and the distance between the inverter location and the step up transformer did not lend itself to high voltage feedback signals. Therefore, provisions were made to use the 480V signals and scale the relative control gains accordingly. This work remains in progress and once enabled, this control allows the plant to support the utility with various grid support features similar to those provided by traditional power generation equipment such as synchronous generators. The plant controller is also capable of performing open loop regulation of without voltage and current feedback of a remote point on the power system. To do this the controller has to be given an equivalent model of the distribution and/or transmission system in between the plant's location and this remote point.

7.4 Remote Site Connectivity

GE and APS have also started work on integration of the SunIQ SCADA server to the APS company historian. This topic is being carefully reviewed as questions around network security are discussed. Furthermore, Figure 81 is a typical one-line communication diagram used in GE's renewable energy installations. APS and GE gain access to the site through an internet connection which will connect each corporate network to a privately managed router and IP network. The built in server hardware has two Ethernet ports, configurable by each party to match their own IP network. This enables connectivity to inverter and SunIQ web HMI screens for remote plant control. It also enables historian integration for data collection through OPC. Furthermore, the remote connectivity provides both parties with monitoring and diagnostics capabilities so any operational issues are quickly identified and resolved.

Figure 81: Typical GE / Customer Communication arrangement

7.5 Data Collection and Initial Analysis

Data relating to ambient, power grid and operating conditions is collected via the built in data collection system of the GE Inverter. This data consist of 187 variables. The data includes both analog and digital values including voltage, frequency, solar irradiation, circuit breaker status, power production, etc. The sampling rate for longer term acquisitions of these variables is programmable with a floor value of 0.1 seconds. The data presented in this report has been collected at a 0.5 second sampling rate.

It is also important, for the subsequent analysis, to keep in mind the relative size of the available PV installation and the capacity of the inverter connected to it. The PV panel installation has an approximated peak output of 70-80kW. The GE utility scale inverter is sized to 700kW; therefore max inverter loading at the STAR site is about 10% of the inverter rating. To contrast collected data and compare preliminary analysis results, data from a clear day and a cloudy day was used. These profiles can be seen in Figure 84.

Figure 82: Irradiance profiles for May 18th & 19th 2011 in Tempe AZ

Upon inspection of multiple clear days it is presumed that the solar irradiance sensor is mounted in an unfavorable position. Specifically, during noon time, there appears to be an obstruction that covers the sensor, giving it the appearance of could cover. However, this variability is not seen in the power output, therefore this leads to the conclusion that it must be an obstruction around the irradiance sensor. This will be corrected during the next site visit.

Figure 83: Inverter power production during May 18th & 19th 2011 in Tempe AZ

Figure 84: Irradiance profiles for Nov 29th and Dec 6th 2010 in Tempe AZ

Furthermore, as can be expected, the resulting power output shares similar characteristics with the corresponding irradiance profile. Referencing Figure 85, inverter power production on November 29th is smooth and continuous, whereas the inverter power output for December 6th fluctuates much more. It is interesting to note that the power production and irradiance profiles are very similar, demonstrating that large inverters are capable of following rapid changes in irradiance even at such low loading. However, solar intermittency is a source of concern, as fluctuations in inverter power production can strain local voltage stability and cause further reactionary measures by automatic power systems protection equipment, such as capacitor bank switching and voltage tap changes. These automatic correctional measures are undesirable as they chase short time transients in solar energy, as is the case with cloud passing, and therefore unnecessarily wear out equipment.

Figure 85: Inverter power production during Nov 29th and Dec 6th in Tempe AZ

As is illustrated in Figure 85, power production during both days starts by the inverter attempting to start after the input DC voltage reaches a certain threshold. The inverter is a two stage design,

which incorporates an input DC boost converter, allowing it to boost DC voltage to values suitable for AC production. The input stage allows the inverter to start at lower DC voltages compared to single stage inverters which rely on DC voltages reaching peak AC voltage values before starting. When the inverter attempts a start it will try to generate a minimum of approximately 20kW before remaining in operation. This is to cover expected losses of a 700kW inverter which has a certified CEC rated 97% efficiency. If the available power is less than the minimum, the inverter will shut off for a predetermined period of time to wait for higher solar irradiance and then try again. This is represented on Figure 85 and is sometimes referred to as “chatter.” The term refers to the noise generated by the toggling of AC contactors during inverter attempts to start. In practice, chatter is reduced to one or two attempts as inverter manufacturers set DC startup voltages close to values where the installed PV array can support the minimum power production requirements. However in the case with the STAR installation, the PV installation is undersized compared to the inverter capacity, this results in additional “chatter” events.

In Figure 86, a comparison of the two selected days is made in order to quantify the effects of power induced voltage fluctuations. The graph is a scatter plot with points representing voltage and power at a particular time during the day. The vertical axis represents grid voltage at the AC output of the inverter, and the horizontal axis represents inverter power production.

Figure 86: Voltage variation as a function of inverter power production for Nov 29th and Dec 6th 2010 in Tempe AZ

It can be seen from the plot in Figure 86 that more voltage variability exists during inverter power generation on December 6th when compared with November 29th. It should be noted that APS STAR site has multiple solar inverters connected to the same medium voltage connection; therefore, voltage fluctuations and overall voltage trend may be the result of all inverters connected at the site.

7.6 Testing of SunIQ (SCADA) enabled features

Many of the advanced features available with the SunIQ system involve functionality not allowed by the UL1741 standard. The team required more time than anticipated to evaluate, design, and create conditions at the STAR site which would allow these features to be tested

safely. The testing performed by the project team at STAR was detailed in the STAR Test Plan attached as an Appendix to this report. Basic testing of several functions such as power curtailment and ramp-rate control was accomplished by GE during the commissioning process. All test data showed operation within the expected range.

The SunIQ can be operated in the following modes:

SunIQ Voltage Regulation Mode: The voltage regulation mode features the ability of the solar plant to regulate voltage at the point of electrical interconnection with the utility grid. This feature is aimed at maintaining constant or reduced voltage fluctuation, at the point of interconnection, due to the inherent intermittency of solar energy. The benefits of enabling this feature include reduced cycling of power system voltage regulation equipment and simpler integration of renewable energy plants with voltage based protection equipment.

SunIQ Power Factor Regulation Mode: The power factor regulation mode enables plant owners to set the power factor at the point of interconnection with the grid. In many cases the power factor value is agreed upon with a utility and can be dynamically adjusted throughout the day.

SunIQ Ramp Rate Control Mode: In this mode the SunIQ has ability to control the plant's power ramp rate. It is important to understand that the plant's ramp rate can only be controlled when power is rising, for example reconnecting after a grid event or after a cloud system has passed and available power exceeds current output. Presently, ramp rates cannot be controlled if the reduction in power output is unintentional, for example due to cloud cover or severe grid event which forced the disconnection solar plant from the grid. Future additions of energy storage and improved forecasting techniques will may one day aid in controlled ramp rate reductions due to intermittent energy sources.

However, ramp rates can be controlled when reducing output of a solar plant due to a planned shutdown or curtailment command. The ramp rate function allows a gradual transition of electrical load between the solar plant and other generation sources as the solar plant's power output ramps down or up.

SunIQ Power Curtailment Mode: In this mode the SunIQ is used to maintain a reduced or curtailed power output level. This feature is useful if the customer plant owner decides it is beneficial to reduce power output of the plant to some constant value. Furthermore, this function is able to operate as long as the curtailed power level is less than the total available power. For obvious reasons, one cannot regulate a solar plant's output power to a level higher than that of the available power.

SunFree VAr Mode: In this mode the SunIQ can be used to regulate voltage at the POI even when no sun is present.

Sun IQ Park Startup/Shutdown: This mode allows the controlled startup and shutdown of large solar plants. This feature enables SunIQ to communicate with each inverter and command startup and a gradual increase in power towards maximum power production or to some customer or utility requested curtailment set point.

Use of OPC DA Server Application: The SunIQ system supports an OPC DA Server Application in which all-key plant data can be passed to a third party OPC Client on a real time basis. OPC²⁹ is an open standard used globally in industrial automation and enterprise systems.

ODBC: GE provides customer access to the SunIQ system's SQL historical database through Open Database Connectivity (ODBC). ODBC is an Application Programming Interface (API) that allows a programmer to extract data from the database.

SunIQ Automatic Report Generation: The SunIQ Web HMI provides automatic report generation capabilities on such variables as plant availability, overall power production, grid statistics, etc. This feature will be available to authorized APS personnel.

Further testing of these features will be accomplished in Phase 2, and data collected from Phase 1 testing will be extracted and analyzed.

7.7 Future Inverter Work

During Phase I, the project team was able to use the experience gained with the UL1741 issue and with data collection and dissemination practices to improve the processes for Phase 2. At the beginning of Phase 2, the GE project team will use the RTDS setup to prepare for inverter deployment at Flagstaff in 2011 and will share results with APS during biweekly meetings as they become available. Additionally, GE will work with APS to develop a test-plan for the Flagstaff site.

Based on the results of Phase 1, future phases of this project will include extensive testing of the inverter using GE's RTDS system and models of the Flagstaff feeder. The project may also implement a UL-approved inverter on the Flagstaff feeder until GE is able to certify its inverter to the UL standard. Whether using a UL-approved GE inverter or another manufacturer's inverter, Phase 2 will include interconnection of the utility scale inverter operating with few advanced features. Once interconnection has taken place, the project team will apply for permission to enable the voltage regulation and/or ride-through capability of the inverter. This more measured approach will be used to get APS comfortable with allowing the operation of an inverter outside of the regulations stipulated in the UL1741 standard and will allow GE to provide additional background data on the anticipated performance of the inverter under the conditions present at the Flagstaff feeder.

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8 Conclusions and Lessons Learned

Phase 1 has provided many insights into the process behind implementing high penetration PV projects. Some of the major conclusions from Phase 1 are as follows:

- Careful consideration must be given when designing a data acquisition system for use in high penetration PV cases. The system must be designed to capture and synchronize both electrical and environmental data with sufficient resolution to adequately capture a variety of potentially disruptive phenomenon. Transmitting these data even on a small scale can provide significant storage and communication challenges. Additionally, these storage and communication hurdles can cause data acquisition equipment to be underutilized. For these reasons, continuing phases will employ data acquisition systems that can preprocess data to make use of the higher sampling rates available from the data acquisition equipment, allowing the project team to obtain maximum benefit from the equipment while minimizing the data that need to be communicated and stored.
- Accurately modeling distribution feeders to the level necessary to analyze the impacts of high penetrations of intermittent resources is an involved process. Even though a utility may have data from various separate databases (GIS, DMS, etc.) describing their systems in significant detail, since these databases were not intended to be used for model development, gaps and inaccuracies may manifest in electrical models developed from these sources. Even with detailed analysis, building a model that accurately represents the electrical system down to the customer meter will likely be an iterative process, checked and re-checked against data from field devices.
- Utilities have gathered great experience in the application of rotating power generation equipment, and some also have experience with power electronic aided energy shaping. However, many utilities are just beginning to add large and small scale power electronics to their grid. Power electronic systems, such as the PV inverter described in this report, offer many potential benefits to utilities but behave differently than traditional generation. Lack of familiarity with this new technology and lack of results from field demonstrations can lead to hesitation on behalf of the utility in going forward with broader power electronic based solutions. A major goal of this project is to assist utilities in gaining experience and familiarity with power electronics, their requirements, and their potential economic and operational benefits.
- Some manufacturers offer inverters with capabilities that exceed the requirements of UL1741/IEEE1547. Many of these manufacturers are also involved in the standards committees and efforts to update the standards to include advanced functionality of distributed resources. However, experience in this and other projects indicate these advanced functions may be difficult to implement without support in applicable standards – even during a research project. Manufacturers, utilities, and standards committees will have to work more closely together to be able to implement and test these “smart inverters” before they will be widely accepted by utilities for connection to the US power grid.

Through project member participation, many of the results and insights gained from Phase 1 and continuing project phases will help shape developing standards. Some of the standards that will be influenced by this project are discussed below.

- IEEE P1547.7 - The intent of IEEE P1547.7 Guide to Conducting Distribution Impact Studies for Distributed Resource Interconnection is to provide a methodology for engineering studies necessary to assess the impact of distributed resources on the grid. The modeling and simulation techniques used in this project will add much needed input to this knowledgebase by providing real world experiences with distributed resource integration.
- IEEE P1547.8 - The intent of IEEE 1547.8 Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Standard 1547 is to expand the implementation strategies used for interconnecting distributed resources with the grid. The future phases of this project will provide insight into these expanded implementation strategies in a high penetration scenario.
- IEEE 2030 - The intent of IEEE P2030 Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), and End-Use Applications and Loads is to provide a knowledgebase to address Smart Grid interoperability. Lessons learned from communication, control, data storage, and analysis utilized in this project will provide resolutions to problems and a valuable reference for those wishing to achieve Smart Grid interoperability.

APPENDIX A

Data Acquisition System Prototypes

Phase I End Report

APS-High Penetration Solar Deployment

Devarajan Srinivasan

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Client: APS

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Data Acquisition System Prototypes

Introduction

This report summarizes the work done for Task Code 2.0 “Development of Field Data Acquisition Package”, under DOE Award “High Penetration Solar Deployment - DE-EE0002060” for Phase I, ending December 2010.

In Phase I, Task Code 2.0 involved developing prototypes for field data acquisition systems (DAS) that will be deployed under the High Penetration Solar Deployment (HPSD) project in Flagstaff, AZ.

The different DAS that will be deployed for the HPSD project are:

1. Weather Station (WS) DAS
2. Customer Premise ac DAS
3. Customer Premise dc DAS
4. Feeder DAS

Prototypes were built for the weather station and customer premise ac DAS at the Arizona Public Service (APS), Solar Test and Research (STAR) Center, in Tempe, AZ. The prototypes included system design, sensor and other hardware mounting, wiring, software, and field testing of the DAS.

Designs were completed for the customer premise dc and feeder DAS. The designs included preliminary system design and procurement of sensors and other hardware.

Weather Station DAS Prototype

A weather station prototype was constructed at the STAR center to prove design principle and provide a training station for field installation. The weather station prototype consists of weather sensors mounted on a 1” rigid pipe upright. The sensors are wired to a Campbell Scientific (CSI) CR1000 data acquisition system. The weather data are sampled and stored at 1s interval. A GPS receiver is used to accurately set and maintain the system clock.

A wireless radio network is used to create an Ethernet network for communication to the CR1000. Data are transferred to the APS network using the DNP3 protocol over TCP/IP.

CSI LI200X pyranometers are used to measure global horizontal (GHI) and south-latitude tilt (LATs) irradiance. A CSI HMP50 temperature and relative humidity probe is used to measure site temperature and relative humidity. A CSI CS106 barometer measures atmospheric pressure. A RM Young heated rain bucket is used to measure precipitation, including snowfall. A CSI wind sentry set is used to measure wind speed and direction.

Weather Station Mounting

The weather station prototype is mounted on an upright 1" rigid pipe as shown in Figure 87 and Figure 88. Figure 89 shows a photograph of the weather station prototype sensor configuration at the STAR Center, taken from the South-East, looking towards North-West.

As shown in Figure 87, the GHI sensor should be the top-most sensor in the WS to avoid 360° shading from any adjacent sensor. The mount can be aligned in any direction, but south facing is recommended. The sensor mount has a bubble level and leveling screws that can be used to ensure horizontal mounting.

The LATs sensor is also mounted on a similar sensor mount. A 12" cross-arm, pointing south, is mounted on the rigid pipe. The LATs sensor mount is attached to the cross-arm such that the tilt angle of the sensor is equal to the latitude of the site. The temperature and relative humidity sensor are installed inside a radiation shield. The radiation shield is mounted on the vertical upright, just below the LATs cross-arm mount. The shield is oriented towards the North.

Figure 87. Li-COR and HMP50 Mounting

As shown in Figure 88, a 6-foot, cross-arm is mounted on the vertical upright, oriented east-west. Two 12" vertical cross-arms are installed at the ends of the horizontal cross-arm.

The rain bucket is installed on the west vertical cross arm. The rain bucket has a bubble-level and mounting screws to level the bucket. The wind speed and direction sensor set is installed on the east vertical cross-arm. The axis of the wind-sensor set should be oriented north-south with the wind vane to the north and the rotating cup anemometer to the south. The GPS sensor mount can be installed on the horizontal cross arm or the vertical upright. It can be moved around to identify the best location depending on signal reception. The barometric pressure sensor is mounted inside the DAS enclosure and not shown in the above figures. The wires from all the sensors are wired into the DAS enclosure.

Figure 88. Rain, Wind, and GPS mounting

Figure 89. View from South-East of weather station prototype sensors

Weather Station Electrical Sub-systems

The weather station prototype electrical wiring consists of three sub-systems:

1. Power wiring sub-system
2. Sensor wiring sub-system
3. Communication wiring sub-system

The power wiring sub-system is shown in Figure 90. The weather station prototype is powered using 120 V, 1 Φ , grid supply. A plug in transformer and power supply with internal battery is used to power the CR1000 DAS. An IDEC 24V, 60W power supply is used to power the GE MDS radio. If the single-phase supply is lost, then communication using the MDS radio is interrupted. Another plug in transformer is used to supply power to the heater built into the RM Young 52202 heated rain bucket. The heater also relies on available single-phase grid power and will shut down if the grid is lost.

The sensor and communication wiring sub-systems are shown in Figure 91. The different sensors are wired into differential (DIFF), single-ended (SE), pulse (P), excitation (Vx), and control (C) ports on the CR1000. A Cat6, cross-over cable connects a NL120 module on the CR1000 to the LAN port of the MDS radio. The MDS radio is co-axially connected to an antenna through a surge-suppressor.

Figure 90. Power wiring sub-system

Figure 91. Sensor and communication wiring sub-systems

Weather Station DAS Enclosure

The CR1000, related power, and communication equipment are mounted inside a 30"x30"x12", NEMA-4, carbon-steel enclosure. A large enclosure was chosen for the prototype to ensure that changes to the design can be easily accommodated. Figure 92 shows a photograph of the weather station enclosure.

Figure 92. Weather station prototype enclosure

Based on the prototype design, it is estimated that the production DAS enclosures will be approximately 20"x20"x08". A preliminary layout is shown in Figure 93.

The DAS enclosure consists of terminal blocks to terminate all the sensor wires from the weather station. It has a circuit breaker and terminals for running 120 V power. The ac power is used to charge a 7 Ah battery, which provides uninterruptible, clean, 12V power to the CR1000 system. In addition, space is available to mount communication interfaces similar to the GE MDS radio shown in Figure 93. A thermostat-controlled heater is also being designed for use in colder climates.

Figure 93. Preliminary DAS enclosure layout

Weather Station Programming and Testing

The CR1000 is programmed to sample data every 1s. The calibration factors (multiplier and offset) of various sensors are programmed into the CR1000. The barometric pressure sensor is only powered every 15 minutes, so the current pressure reading is over-written by the previous valid pressure measurement. Both raw data (mV, Hz, counts) and processed data are stored in a table every second.

Every second, the CR1000 receives a text string array from the GPS unit. This text array is parsed and time information is used to synchronize the data logger clock with the GPS clock. Time is only synchronized if adequate GPS signal is acquired.

Every second, the CR1000 updates a DNP3 slave table, which is read by a real-time automation controller and the data is fed into the APS “PI-historian” database.

Tests were performed to verify the raw data, processed data, data storage, time synchronization, data communication through DNP3 and TCP/IP, and supply power loss operation have been tested at STAR.

Customer Premise ac DAS Prototype

A 4 kW photovoltaic (PV) system was installed on a mock-up roof at STAR. A customer premise ac DAS prototype was constructed at the STAR center to prove design principle and provide a training station for field installation.

The customer premise ac DAS prototype consists of a Schweitzer Engineering Laboratories SEL-734 advanced metering system. The SEL-734 samples ac voltages and currents at a high sample rate, calculates, and stores various power quality information. A wireless radio network is used to create an Ethernet network for communication to the SEL-734. Data are transferred to the APS network using the DNP3 protocol over TCP/IP. The SEL-734 time is synchronized to the APS network through the DNP3 protocol.

Customer Premise ac DAS Electrical System

The SEL-734 meter electrical system is shown in Figure 94.

Meter grade current transformers are used to measure inverter output current. The meter dot is oriented towards the inverter, so the meter measure positive power when the PV system is generating power. In other words, the PV inverter is the source and the utility grid is the load.

A three-phase, supplementary, 3A breaker is used to protect the voltage measurement to the SEL meter. Control power is derived from the inverter (line) side of the CTs. Hence, control power is not included in energy fed to the utility, when the PV is producing power and is included in parasitic loads fed from the utility grid.

An IDEC 24V, 60W, power supply is used to power the GE MDS radio and the SEL-734. If the single-phase supply is lost, then the meter stops recording data and communication using the MDS radio is interrupted.

A Cat6, cross-over cable connects the SEL-734 to the LAN port of the MDS radio. The MDS radio is co-axially connected to an antenna through a surge-suppressor.

At STAR, a split-phase inverter is used, so only two phases (L1 and L2) are wired, along with the neutral and ground connections.

Figure 95. Customer premise ac DAS enclosure

Table 9: Equipment List for Weather Station Prototype

Equipment Configuration - Weather Station (Baseline Prototype)			
Item	Part	Instrument Description	Vendor
1	CR1000 -XT -SW	CR1000, -55 to 85 C, 3yr Warranty, Wiring panel	Campbell Scientific
2	17324	CR1000WP Insulated Terminal Cover	Campbell Scientific
3	PS100	12V Power Supply w/Charging Regulator and 7Ahr Sealed Rechargeable Battery	Campbell Scientific
4	9591	Wall Charger 18 Vac, 1.2A Output,110 Vac Input, 6ft cable	Campbell Scientific
5	NL120 -XT -XW	Ethernet Interface, -55 to 85 °C, 4 yr Warranty	Campbell Scientific
6	GPS16X-HVS	GARMIN GPS Receiver w/Integrated Antenna, 15ft Cable	Campbell Scientific
7	17212	GPS16X-HVS Magnetic Mount	Campbell Scientific
8	CM235	Magnetic Mounting Stand	Campbell Scientific
9	HMP50 -L25 -PT	Vaisala Temperature/RH Probe, 25 ft, w/Tinned Wires	Campbell Scientific
10	41303-5A	RM Young 6-Plate Gill Solar Radiation Shield	Campbell Scientific
11	CS106	Vaisala PTB110 Barometer (500 - 1100 hPa), 30 inch cable	Campbell Scientific
12	03002 -L25 -PT	RM Young Wind Sentry Set	Campbell Scientific
13	LI200X -L25 -PT	LI-COR Pyranometer, Fixed Calibration, 15 ft, w/Tinned Wires	Campbell Scientific
14	LI2003S	LI-COR Leveling Base	Campbell Scientific
15	CM225	Solar Sensor Mounting Stand	Campbell Scientific
16	52202	RM Young heated rain gauge, 24 Vac, 8W	RM Young
17	02800.9-00	Stego CS 028 Fan Heater, 150W 120VAC, 50/60Hz, DIN clip	Control Switches
18	01146.9-00	Stego KTO 011 (NC) thermostat, 0 to 60 °C, 120 Vac, 15 A	Control Switches
19		Cisco managed industrial switch	
20	Mercury 3650	GE MDS Radio with mounting bracket	General Electric
21	LSXL	Surge suppressor for MDS Radio	
22	Outdoor Antenna	Outdoor antenna, Cable, and accessories	

Table 10: Equipment List for Customer -Sited DAS Prototype

Equipment Configuration - Customer Premise High Bandwidth DAS (Prototype)			
Item	Part	Description	Vendor
1	SEL 734	Advanced metering system	Schweitzer Engineering Laboratories
2	915900063	HZ, 7XX, Hinged bracket, panel mount	Schweitzer Engineering Laboratories
3	Mercury 3650	GE MDS Radio with mounting bracket	General Electric
4	LSXL	Surge suppressor for MDS Radio	
5	Outdoor Antenna	Outdoor antenna, Cable, and accessories	
6	CR2DARL-500	50:5 A ANSI Metering Class CT	CR Magnetics
7	02800.9-00	Stego CS 028 Fan Heater, 150W 120VAC, 50/60Hz, DIN clip	Control Switches
8	01146.9-00	Stego KTO 011 (NC) thermostat, 0 to 60 °C, 120 Vac, 15 A	Control Switches

APPENDIX B

High Penetration of Photovoltaic Generation Study – Flagstaff Community Power

Arizona Public Service Company

Integrated Test Plan and Evaluation Program: GE Brilliance 700kVA Solar Inverter & SunIQ Solar Plant Controller

V1.0

Authors:

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Arizona State University
National Renewable Energy Laboratory
ViaSol Energy Solutions, LLC

February 2011

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INTRODUCTION

This document describes the appropriate strategies, processes, and motivation used to test the GE Brilliance 700kW solar inverter at the APS STAR test site.

PROJECT OBJECTIVE

The inverter testing described in this document is a part of a larger project. The project will demonstrate how high penetration of photovoltaic (“PV”) systems will affect grid operations of a working, utility distribution feeder. Technologies to ensure the stable and safe operation of the grid when PV generation levels reach or exceed 30% of the total load will be developed and evaluated. Lessons learned will be disseminated across the United States energy sector. The purpose of the testing described in this document is to establish baseline operation of the inverter, get the project participants familiar with the inverter and comfortable with its operation, and to characterize the unique features of the inverter that will help to enable the safe and reliable high-penetration of PV generation on distribution grids.

SOLAR INVERTER

The dynamic impact of PV on system voltage arises from its short-term variability that can be due to shading by clouds, or due to adverse interactions between PV inverters and utility equipment controlling system’s voltage. Variability in solar production can cause voltage regulating equipment on the feeder to operate more frequently than when dealing with load only, which could cause increased wear on transformer tap-changers or reactive compensation switches.

PV inverters could help mitigate these voltage variations by supplying reactive power to the feeder and playing an active role in feeder voltage control, but this has to be addressed in the overall system design. If left unattended, inverters and utility equipment can enter a cycle of control actions and, in the worst-case scenario, cause a destructive number of operations on utility equipment or observable flicker in customers’ service voltage. Furthermore, multiple inverters providing reactive power support have to be designed to ensure even sharing of their reactive power contributions, and to prevent differential mode oscillations. To make this practical, a set of simple performance requirements has to be developed for use by equipment manufacturers.

The GE 700 kVA inverter’s control system can regulate voltage and power in real time. Like a conventional power plant, it is able to supply reactive power to the grid when it is needed, regulating system voltage and stabilizing weak grids. Communication between the inverter and utility-owned voltage regulation equipment enables coordinated voltage regulation along the entire length of the feeder.

GE Energy’s Utility Scale PV Inverter is based on GE’s proven wind turbine control design. Over 8000 MW-scale wind inverters have been produced and fielded to date, providing an experience base in this class of inverters that is unprecedented in the industry and has resulted in superior cost and reliability positions. The inverter can implement a number of grid support features such as ride-through and voltage support.

GE's utility-scale solar inverter will be used to provide power from a 500kW solar field. The inverter's grid-friendly features make it ideal for use in a high-penetration environment and are intended to enhance capability and overcome current limitations in a variety of key ways, among which are the following:

- Increased distribution system reliability by providing ride-through capability through most transmission fault events;
- Better immunity to voltage sags and avoidance of system voltage collapse due to grid faults by controlling power factor and voltage regulation; and
- Grid reactive power support capabilities through high integration with traditional voltage regulation equipment.

The inverter was placed at the APS Solar Test and Research Center ("STAR") facility for initial testing to ensure integration with APS systems and functionality using a PV source of with up to 80 kW. STAR will also provide an opportunity to test the inverter's VAR support functions. The development of a formal plan for this testing is the purpose of this document.

Although not all effects on the power system can be seen during the operation of a single inverter operating on a single feeder, laboratory and field-test results combined with modeling and simulation will be used to validate the benefit of each of the advanced grid support features of the inverter. The testing described in this document is one step along the path to a complete evaluation.

In addition to the inverter testing, data acquisition systems, topologies for communications strategies, SCADA and data historian integration will be tested at the STAR facility prior to field implementation.

The current inverter and SunIQ test plan is intended to be comprehensive and has been developed to exercise the capabilities of both inverter and SunIQ within parameters controllable by APS and GE. Such events as power system faults are unplanned however the inverter and SunIQ are setup to capture data of such events as they occur. While the current test plan has been developed taking into consideration the current project status, it is conceivable that the present test plan will see modifications driven by developments during Phase 2 of the project. The intent of any required modifications will be to remain relevant to the project objectives and to avoid any reduction in scope unless these are no longer relevant, inapplicable or otherwise prohibited due to utility operating and safety guidelines.

ABBREVIATIONS

A – Amperage/Amps
AC – Alternating Current
AI - Analog Input
AO - Analog Output
APS – Arizona Public Service
CB - Circuit Breaker
CT - Current Transformer
DI - Digital Input
DO - Digital Output
GE – General Electric
GUI – Graphical User Interface
JSA - Job Safety Analysis
kW - Kilo Watts
LVRT – Low Voltage Ride Through
MPPT – Maximum Power Point Tracker
MW - Mega Watts
ODBC –Open Database Connectivity
OLE – Object Linking & Embedding
OPC - OLE for Process Control
OSHA - Occupational Safety and Health Administration
PT or VT - Potential or Voltage Transformer
SCADA – Supervisory Control and Data Acquisition
SOP – Standard Operating Procedure
UL – Underwriters Laboratory
V – Voltage/Volts
Vac - Voltage Alternating Current
VAR - Volts Ampere Reactive

SCOPE

In Scope

The 700kW solar inverter test plan defines the testing approach and schedule for the inverter testing at STAR. The test scope includes the following:

- GE Solar Plant System Overview
- Basic inverter, functions and user interface
- Basic SunIQ, functions and user interface
- Basic Trender Setup
- SunIQ Voltage Regulation Mode
- SunIQ Power Factor Regulation Mode
- SunIQ Ramp Rate Control Mode
- SunIQ Power Curtailment Mode
- Park Shutdown/Startup
- OPC / Historian Integration for park data collection
- SunIQ Automatic Report Generation Capabilities

Out of Scope

The following items are considered out of the scope of the 700kW solar inverter test plan and will not be discussed in great detail in this test plan. If desired the following tests may be revisited at a later time after completion of the initial test set.

- UL1741 qualification tests
- Line Drop Compensation
- Voltage Droop
- Power Frequency Droop Control
- Intentional testing of the Low Voltage Ride Through (LVRT) algorithm
- Testing and characterization of the Maximum Power Point Tracking (MPPT) algorithm

OBJECTIVE

The primary objectives of this testing are:

Demonstrate advanced inverter features that may be new to engineers used to standard solar inverters

Familiarize the engineers and technicians at the APS STAR facility and the Flagstaff feeder with the inverter and its operation

Familiarize interconnection engineers with the benefits of advanced inverter features for the effective management of intermittent renewable energy sources

ROLES AND RESPONSIBILITIES

GE

Commissioning engineers from GE will be present and assist with the inverter commissioning. GE will also supply manuals, data sheets, and connection diagrams as appropriate. GE will have primary responsibility for the test-plan.

APS

APS will supply test personnel and test equipment including (but not limited to) isolation transformer, reconfigurable RLC load, mounting and racking, wiring, electrical interconnection materials, computing and networking equipment.

TEST METHODOLOGY

PURPOSE

GE Solar Plant System Overview

The purpose of this section is to familiarize the parties involved with this testing document with the GE solar power system architecture. The section will cover only main topics and will not dive into significant detail. The main objective of this section is to provide a general understanding of the various components of a solar plant and their relationship to another.

Basic inverter, functions and user interface

The purpose of this section is to familiarize authorized APS personnel with the physical inverter hardware, safety precautions and basic operation such as power up shut down, reset and maintenance. Furthermore, this section will also cover introductory use of the inverter's graphical user interface (GUI).

Basic SunIQ, functions and user interface

The purpose of this section is to familiarize authorized APS personnel with the physical plant controller (SunIQ) hardware, safety precautions and basic operation such as power up shut down, reset and maintenance. Furthermore, this section will also cover introductory use of the plant controller's graphical user interface (GUI).

Basic Trender Setup

The purpose of this test section is to familiarize authorized APS personnel with trender setup and configuration. The trender tool is very useful to monitor system variables over time using GE's ToolboxST software, installed on the SunIQ platform.

SunIQ Voltage Regulation Mode

The voltage regulation mode features the ability of the solar plant to regulate voltage at the point of electrical interconnection with the utility grid. This feature is aimed at maintaining constant or reduced voltage fluctuation, at the point of interconnection, due to the inherent intermittency of solar energy.

The benefits of enabling this feature include reduced cycling of power system voltage regulation equipment and simpler integration of renewable energy plants with voltage based protection equipment.

SunIQ Power Factor Regulation Mode

The power factor regulation mode enables plant owners to set the power factor at the point of interconnection with the grid. In many cases the power factor value is agreed upon with a utility and can be dynamically adjusted throughout the day.

SunIQ Ramp Rate Control Mode

The purpose of this section is to demonstrate the solar plant controller's (SunIQ) ability to control the plant's power ramp rate. It is important to understand that the plant's ramp rate can only be controlled when power is rising, for example reconnecting after a grid event or after a cloud system has passed and available power exceeds current output.

Presently, ramp rates cannot be controlled if the reduction in power output is unintentional, for example due to could cover or severe grid event which forced the disconnection solar plant from the grid. Future additions of energy storage and improved forecasting techniques will may one day aid in controlled ramp rate reductions due to intermittent energy sources.

However, ramp rates can be controlled when reducing output of a solar plant due to a planned shutdown or curtailment command.

The ramp rate function allows a gradual transition of electrical load between the solar plant and other generation sources as the solar plant's power output ramps down or up.

SunIQ Power Curtailment Mode

This test demonstrates the plants ability to maintain a reduced or curtailed power output level. This feature is useful if the customer plant owner decides it is beneficial to reduce power output of the plant to some constant value.

Furthermore, this function is able to operate as long as the curtailed power level is less than the total available power. For obvious reasons, one cannot curtail a solar plant's output power to a level higher than that of the available power

Sun IQ Park Startup/Shutdown

The purpose of this section is to demonstrate the controlled startup and shutdown of large solar plants. This feature enables SunIQ to communicate with each inverter and command startup and a gradual increase in power towards maximum power production or to some customer or utility requested curtailment set point.

OPC DA Server Application and ODBC Connectivity

OPC DA Server Application

The SunIQ system supports an OPC DA Server Application in which all-key plant data can be passed to a third party OPC Client on a real time basis. OPC (<http://www.opcfoundation.org/>) is

an open standard used globally in industrial automation and enterprise systems. Interoperability is assured through the creation and maintenance of open standards specifications. OPC is open connectivity via open standards. Based on fundamental standards and technology of the general computing market, the OPC Foundation adapts and creates specifications that fill industry-specific needs.

ODBC Connectivity

GE provides customer access to the SunIQ system's SQL historical database through Open Database Connectivity (ODBC). ODBC is an Application Programming Interface (API) that allows a programmer to easily extract data from the database.

SunIQ Automatic Report Generation Capabilities

The SunIQ Web HMI provides automatic report generation capabilities on such variables as plant availability, overall power production, grid statistics, etc. This section will focus on demonstrating the use of these features to authorized APS personnel.

TESTING PRELIMINARIES

Safety Equipment and Procedures

Lockout/tag-out

FR clothing

Safety glasses, hardhats, steel toe shoes

Only trained and qualified personnel authorized

Test site layout

Figure 96: APS STAR Center GE Inverter & SunIQ Setup

TEST DETAILS

GE Full Solar Plant System One-Line Overview

Figure 97: GE Full Solar Plant System One-Line Overview

Basic inverter, functions and user interface

The inverter cabinet is a self-contained outdoor rated enclosure, with all the necessary power electronics and system protection components. The inverter focuses on robust delivery of power. If so desired by the utility, the inverter may be required to ride through grid events as part of its Low Voltage Ride Through (LVRT) capabilities. The inverter is also capable of supplying reactive power within its nameplate rating. The intelligent reactive power dispatch command, for such non-UL1741 features as voltage regulation, is provided by SunIQ, which is described in the following section.

Basic SunIQ, functions and user interface

Physically the SunIQ system cabinet includes all the hardware needed for the SCADA and Plant level control functionalities. Furthermore, the SunIQ system has the interface screens to manually enter the set points (such as Voltage set point, MW curtailment set point, etc) for plant level control as well as to view the settings - either locally at the cabinet or remotely. Alternatively, the system is capable of receiving analog and digital I/O through which the settings can be manipulated by third parties such as grid operators.

Signal Name	System Quantity
InGrid_PwrAct_r32	Actual park power
CtrlPwr_PwrSetpSRL_r32	Actual power reference setpoint
InINV_PwrAct_r32	Actual power of the inverters connected
InINV_PwrPsbl_r32	Possible power of the inverters connected
CtrlPwr_PwrRegDmd_r32	Power regulator demand value
SM_CtrlPwr_ControlActive	111_Power control active
SM_CtrlPwr_ActPwrLimited	019_Park active power limited
SM_CtrlPwr_IregLimited	127_Power control integrator in limit

Table 11: SunIQ Active Power Signals

Signal Name	System Quantity
InGrid_PwrAct_r32	Actual park power
CtrlPwr_PwrSetpSRL_r32	Actual power reference setpoint
InINV_PwrAct_r32	Actual power of the inverters connected
InINV_PwrPsbl_r32	Possible power of the inverters connected
CtrlPwr_PwrRegDmd_r32	Power regulator demand value
SM_CtrlPwr_ControlActive	111_Power control active
SM_CtrlPwr_ActPwrLimited	019_Park active power limited
SM_CtrlPwr_IregLimited	127_Power control integrator in limit

Table 12: SunIQ Reactive Power Signals

SunIQ Voltage Regulation Mode

The following steps are required to verify the operation and stability of SunIQ Plant Control System in voltage regulation mode. Set-points for the voltage regulation mode can be changed from the SCADA WEB HMI screen and / or by the appropriate SunIQ Plant Control System hardware input. Use the configured signals of Table 11 and Table 12 to track the test steps.

Caution!

Following test may cause grid voltage fluctuations or resonances. Approval must be taken from the customer & utility company prior to conducting these tests.

Step 1 - Match the set-point to the actual line voltage. Observe and record the value(s) of present set-point for the system voltage at site in the commissioning and acceptance document. Change the set-point by 3 % (Consult customer to ensure that 3 % step is appropriate under the given test scenario) of the present set-point.

Verify the voltage slew rate set-point limiter parameter P_CtrlVolt_VregSRL_r32 is set correctly as per the site requirements.

Step 2 - Observe the system voltage achieves the new set-point value with minimum overshoot and within time frame as selected by the parameter. Trend the following system voltage signal voltage set-point, voltage feedback, actual reactive power, reactive power command as per the signal definition in Table 4 and Table 5. Look to section 7.6 in the Installation & Commissioning manual for more information.

Step 3 - Capture the screen snap shot of the respective trend and place it in this commissioning and acceptance document. Verify the under damped response of the voltage regulator. The under-shoot is normally less than 0.1 % of the rated.

Step 4 - Change the voltage set-point to the original setting as recorded in step 1. Repeat steps 2 & 3 to ensure the voltage goes back to the original set-point.

Step 5 - Run the farm in voltage regulator mode for about 5 minutes, and trend the system voltage, voltage set-point, voltage feedback, actual reactive power, and reactive power command.

Step 6 - Observe that the system voltage remains constant with changes in farm power. Trend the voltage signal(s) along with the solar farm power signal(s). Take a snap shot of the trend and place it in the commissioning and acceptance test document.

NOTES:

SunIQ Power Factor Regulation Mode

The following steps are required to verify the operation and stability of the SunIQ Plant Control System in power factor regulation mode. Similarly the power factor set-points can be changed from the SCADA Web HMI screen or hardware input.

Caution!

Only perform this test after a successful voltage regulator test.

The following test may cause grid voltage fluctuations or resonances. Approval must be taken from the customer & utility company prior to conducting these tests.

PF setpoint must be incremented or decremented in a manner such that there is no system over voltage.

If the system voltage is high, decrease the power factor set-point value. If the system voltage is low, the power factor set-point must be incremented for the test. The increment/decrement steps must not exceed more than 0.01 to 0.02 of the current power factor value at site.

Add the following signals to the trender window in addition to the signals configured in Table 11 and Table 12:

Signal Name	System Quantity
InGrid_PhiPSeq_r32	Actual measured phi value (power factor)
CtrlPf_PhiSetpSRLIn_r32	Phi demand

Step 1 - Start the trend recorder on the ToolboxST trender with the system voltage, actual measured phi and phi demand. Check if the demand phi slew rate limiter is set to the site-specific requirements (P_CtrlPf_PhiSRL_r32).

Match the set-point to the actual power factor. Select the power factor regulation mode from the SCADA Web HMI screen.

Step 2 - Observe that the system smoothly transfers from the voltage regulator mode to power factor regulator mode with the park power stable. Change the power factor set-point by +/- .02 then wait 3-5 minutes. Monitor the actual measured phi and phi demand value.

Step 3 - Capture the screen snap shot of the respective trend and place it in this commissioning and acceptance document.

Step 4 - Observe the current set-point value(s) for the system power factor, and record this value in the acceptance test document. Consult the customer to ensure that the step change is appropriate under the given test scenario. Change the set-point by 0.01 or 0.02 (as it was done in step 2) of the current set-point from the SCADA Web HMI screen. For example, if the PF at site is 0.9, then change it to 0.91 or 0.92.

Step 5 - Observe the system power factor achieves the new set-point value with minimum overshoot. Trend the system power factor signals actual measured phi and phi demand.

Step 6 - Capture the screen snap shot of the respective trend, and place it in this commissioning and acceptance document.

Step 7 - Change the power factor set-point to the original setting as noted in step 1. Repeat steps 5 & 6.

Step 8 - Run the farm in power factor regulation mode for about 5 minutes and trend the system power factor.

Step 9 - Observe that the system power factor remains constant with change in farm power. Trend the power factor signal(s) along with the solar farm power signal(s). Take a snap shot of the trend and place it in the commissioning and acceptance test document.

SunIQ Reactive Power (VAR) Regulation Mode

The following steps are required to verify the operation and stability of the SunIQ Plant Control System in VAR regulation mode. Similarly the VAR set-points can be changed from the SCADA Web HMI screen or hardware input.

Caution!

Only perform this test after a successful voltage regulator test.

The following test may cause grid voltage fluctuations or resonances. Approval must be taken from the customer & utility company prior to conducting these tests.

PF setpoint must be incremented or decremented in a manner such that there is no system over voltage.

If the system voltage is high, decrease the VAR set-point value. If the system voltage is low, the VAR set-point must be incremented for the test. The increment/decrement steps must not exceed more than 5% of the VAR capability of the farm (InINV_SumPsblPosRpwr_r32).

Add the following signals to the trender window in addition to the signals configured in Table 11 and Table 12:

Signal Name	System Quantity
CtrlVar_RpwrSetpSRLIn_r32	VAR demand
CtrlVar_VoltVarSetp_r32	Voltage reference output from VAR regulator

Step 1 - Start the trend recorder on the ToolboxST Trender with the system voltage, actual measured reactive power and VAR demand. Check if the demand reactive power slew rate limiter is set to the site-specific requirements (P_CtrlVar_RpwrSRL_r32). Match the set-point to the actual reactive power. Select the VAR regulation mode from the SCADA Web HMI screen.

Step 2 - Observe that the system smoothly transfers from the voltage to the VAR regulation mode with the park power stable. Monitor the actual measured reactive power and demand value.

Step 3 - Capture the screen snap shot of the respective trend and place it in this commissioning and acceptance document.

Step 4 - Observe the current VAR set-point value(s) and record this value in the acceptance test document. Consult the customer to ensure that the step change is appropriate under the given test scenario. Change the set-point by +5% of the VAR capability from the SCADA Web HMI screen, then wait 3-5 minutes.

Step 5 - Observe the reactive power achieves the new set-point value with minimum overshoot. Trend the measured reactive power and VAR demand signals.

Step 6 - Capture the screen snap shot of the respective trend, and place it in this commissioning and acceptance document.

Step 7 - Change the reactive power set-point to the original setting as noted in step 1. Repeat steps 5 & 6. Document the response time and undershoot.

Step 8 - Run the farm in VAR regulation mode for about 5 minutes and trend the system reactive power.

Step 9 - Observe that the system reactive power remains constant with change in farm power. Trend the reactive power signal(s) along with the solar farm power signal(s). Take a snap shot of the trend and place it in the commissioning and acceptance test document.

SunIQ Ramp Rate Control Mode

The following steps are required to monitor and verify the ramp rates of the solar farm. The farm has to be curtailed to a power set-point approx. 50% under the possible power to have an adequate starting point for the test. The test can only be performed with adequate sun condition to assure that no inverters go offline. Be sure that the inverters are configured for supporting the ramp functionality.

Create the following trend chart with ToolboxST Trender:

Signal Name	System Quantity
CtrlPwr_AvrgRampValueCrv1_r32	Average ramp rate of curve 1
CtrlPwr_AvrgRampValueCrv2_r32	Average ramp rate of curve 2
CtrlPwr_PwrRamp1Value_r32	ramp rate 1 set-point
CtrlPwr_PwrRamp2Value_r32	ramp rate 2 set-point

Caution!

Following test may cause grid voltage fluctuations or resonances. Approval must be taken from the customer & utility company prior to conducting these tests.

Step 1 - Set a power set-point approx. 50% below the possible power of the solar farm. When set-point is reached, wait until the max. dT time of the curves is elapsed to have a defined starting point for the ramp. Enable the ramp control function on the SCADA Web HMI.

Verify the rate setting of curve 1 (setup e.g. 60 s time span) and curve 2 (setup e.g. 240s time span).

Step 2 - Disable the power regulator in the SunIQ Plant Control System and check the status list to verify that the power regulator is stopped. Confirm there is no significant difference between the actual ramp rate and the one selected in the settings. Create a ToolboxST trend with the actual power (InGrid_PwrAct_r32) and number of inverters online (InINV_InvertersOnline_u16). Verify that the measured ramp rates do not exceed the limits determined by the settings in the SCADA Web HMI.

If the ramp rate overshoots the limits, reduce the gain by 0.05 (P_CtrlPwr_RampRateGain_r32) to damp the ramp rate control. It's also possible to increase the gain, if the ramp rate reaction is too slow. After a change in the gain, step 1 and 2 has to be repeated.

Step 3 - Restore the Ramp Control function selection to the pre-test state. (Enable the power regulator, if it is requested for the site).

SunIQ Power Curtailment Mode

The following steps are required to verify the operation and stability of the SunIQ Plant Control System in power curtailment mode.

Similarly the power curtailment set-points can be changed from the SCADA Web HMI and/or screen hardware inputs.

Following test may cause grid voltage fluctuations or resonances. Approval must be taken from the customer & utility company prior to conducting these tests.

Step 1 - Observe the current demand value(s) for the SunIQ Plant Control System power curtailment screen. Record this value in the acceptance test document. Observe the current value for actual power. Consult with the customer to ensure that a 10% step is appropriate under the given test scenario. Change the set-point by 10 % less than the current actual power.

Step 2 - Observe the park power produced achieves the new set-point value with minimum undershoot and by using the configured SRL ramp rate (P_CtrlPwr_RampRateSlewRate_r32). Trend the actual power signal (depends on the park configuration) as defined in Table 4.

Step 3 - Capture the screen snap shot of the respective trend and place it in this commissioning and acceptance document.

Step 4 - Change the park power set point to the original setting as noted in step 1. Repeat steps 2 and 3.

Step 5 - If the volt/VAR/Pf regulator was active when the curtailment regulator was turned on, observe the interaction of this regulator with the power curtailment regulator when power is curtailed and verify that the voltage/VAR/Pf output remains stable. Trend the park power signals along with the actual voltage, VAR and phi value. Take a snap shot of the trend and place it in the commissioning acceptance document.

Park Shutdown/Startup

The following steps are required to verify the ability of the SunIQ Plant Control System to shut-down the farm (command off the inverters at the farm). The farm can be commanded off through a **utility commanded shutdown** that is enabled through a configurable digital input or by using the SCADA Web HMI screens.

In the event the inverter loses communication with the SunIQ Plant Control System, the shutdown command will be cleared automatically and the inverter will restart if there are no other stops active in the inverter.

If a digital output were requested for any of the park shutdown function enable or disable, it should also be verified during each of the steps.

Caution!

Following test may cause either the farm power to curtail, farm to shutdown/start-up or grid voltage fluctuations or resonances. Approval must be taken from the customer & utility company prior to conducting these tests.

Step 1 - Observe and record the value(s) of current transmission system frequency and the active power output of the farm. Select the park shutdown hardware digital input to enable the function. If a digital output confirmation was requested for the site, corresponding SunIQ Plant Control System DO would be turned on to confirm the ON / OFF status of the park shutdown function selection.

Verify and record that the farm shuts down completely within the time frame selected by P_CtrlSS_ParkSDTime_r32. Verify and record that the farm was able to ramp down the power gradually and that the response time was accurate. Note: It may take approximately 30 seconds longer for the last inverter to actually go offline than the setting in P_CtrlSS_ParkSDTime_r32.

Step 2 - The following step will help to verify the startup of the inverters after the shutdown command is released. The parameter P_CtrlSS_ParkSUIntvTime_r32 inverter startup interval time is defined as the time it will take to start one inverter in the farm. The total time to start the entire park is this parameter times the number of inverters in the farm.

Only inverters stopped by the SunIQ Plant Control System (curtailment stop) will be commanded on. The startup sequence of the SunIQ Plant Control System will only run after a farm shutdown command has been released or SunIQ Plant Control System initialization.

Parameter P_CtrlSS_ParkAutoStartEn_b1 is used to enable a farm startup after the shutdown command is removed. This bit should be set for sites that have shutdown requirements.

Verify and record that the farm (inverters on-line with SunIQ Plant Control System) starts up automatically within the time frame selected by P_CtrlSS_ParkSUIntvTime_r32. Verify and record that the farm was able to ramp up gradually and that the response time was accurate.

Step 3 - Restore the park shutdown function selection to the normal operating state.

OPC / Historian Integration for park data collection

Figure 98: GE & Customer One-Line Communications Interface

APPENDIX

$$S_B = 700 \text{ kVA}$$

SC Impedance on 12.5kV side:

- Pos. Seq. : $0.561 + j 0.728$

- Zero Seq. : $1.26 + j 0.728$

- $Z_{pos \text{ Seq}}$: 0.656

- $Z_{zero \text{ Seq}}$: 1.18

$$Z_{\text{Base Low side}} = \frac{.48 \text{ kV}^2}{.7 \text{ MVA}} = 0.32$$

$$Z_{\text{Base High Side}} = \frac{12.5 \text{ kV}^2}{.7 \text{ MVA}} = 223.2$$

Transformer Info:

225 kVA

Prim Volts = 7200 V_{L-N}

Sec Volts = 277 V_{L-N}

Avg. % R = 0.80

Avg. % X = 1.53

Avg. % Z = 1.72

$$Z_B^{Tx} = \frac{.48 \text{ kV}^2}{.225 \text{ MVA}} = 1.024$$

$$Z_B^{Tx} = 1.024 \cdot 1.72\% = 1.76 \times 10^{-2}$$

Transform to 700kVA base ...

$$Z_B^{Tx} \cdot \frac{.7 \text{ MVA}}{.225 \text{ MVA}} = 5.475 \times 10^{-2}$$

$$Z_{\text{Total}} = 0.0576 \text{ p.u.}$$

Inverter minimum $\text{SCCR} = 2.5$

$$Z = \frac{1}{2.5} = 0.4$$

- Short Circuit Impedance on the 12.5kV side

System Impedance:

Positive Sequence: R 0.561 Ohms + J 0.728

0 Sequence: R 1.26 Ohms + J 1.039

- Nameplate of the 480V/12.5kV transformer

According to the GIS, TX # M110695 should be under APN # 4222215 and its average impedance is highlighted in pink in the Excel sheet. The average impedances below are calculated based on the the tested impedance values provided by the manufacturer in the certified test reports for all 3-Phase transformers purchased in 2007 and 2008.

APN #	KVA	Prim. Volts	Sec. Volts	Avg. % R	Avg. % X	Avg. % Z
4222215	225	7200	277	0.80	1.53	1.72

APPENDIX C

TECHNOLOGY TRANSFER ACTIVITIES

April 1, 2010 to June 30, 2010	APS participated at DOE Solar Energy Technologies Program Annual Peer Review in Washington DC
October 1, 2010 to December 31, 2010	ASU and GE gave presentations to Power Systems Engineering Research Center
October 1, 2010 to December 31, 2010	APS, ASU, GE and ViaSol gave presentations to DOE as part of a formal review process in Phoenix
January 1, 2011 to March 31, 2011	APS gave a presentation at DOE/California Public Utilities Commission High Penetration Forum in San Diego
April 1, 2011 to June 30, 2011	APS/NREL delivered a paper and poster at the Institute of Electrical and Electronics Engineers Photovoltaic Specialist Conference
To provide an additional method for sharing content, APS has developed a site at http://www.aps.com/main/green/choice/solar/highpenetration.html	
Team has provided content for the DOE High Penetration Solar Portal: https://solarhighpen.energy.gov/project/arizona_public_service_company	