Costs and Benefits of Smart Feeder Switching

Quantifying the Operating Value of SFS

FINAL REPORT | MAY 31, 2014

NRECA
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Cooperative Research Network

NRECA-DOE SMART GRID DEMONSTRATION PROJECT | DE-OE0000222

Costs and Benefits of Smart Feeder Switching

Quantifying the Operating Value of SFS

FINAL REPORT | MAY 31, 2014

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The National Rural Electric Cooperative Association

NRECA is the national service organization for more than 900 not-for-profit rural electric cooperatives and public power districts providing retail electric service to more than 42 million consumers in 47 states and whose retail sales account for approximately 12 percent of total electricity sales in the United States.

NRECA's members include consumer-owned local distribution systems — the vast majority — and 66 generation and transmission (G&T) cooperatives that supply wholesale power to their distribution cooperative owner-members. Distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable and affordable electric service.

About CRN

NRECA's Cooperative Research Network™ (CRN) manages an extensive network of organizations and partners in order to conduct collaborative research for electric cooperatives. CRN is a catalyst for innovative and practical technology solutions for emerging industry issues by leading and facilitating collaborative research with co-ops, industry, universities, labs, and federal agencies.

CRN fosters and communicates technical advances and business improvements to help electric cooperatives control costs, increase productivity, and enhance service to their consumer-members. CRN products, services and technology surveillance address strategic issues in the areas:

- Cyber Security
- Consumer Energy Solutions
- Generation & Environment
- Grid Analytics
- Next Generation Networks
- Renewables
- Resiliency
- Smart Grid

CRN research is directed by member advisors drawn from the more than 900 private, not-for-profit, consumer-owned cooperatives who are members of NRECA.

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FOREWORD

The National Rural Electric Cooperative Association (NRECA) has organized the NRECA-U.S. Department of Energy (DOE) Smart Grid Demonstration Project (DE-OE0000222) to install and study a broad range of advanced Smart Grid technologies in a demonstration that involved 23 electric cooperatives in 12 states. For purposes of evaluation, the technologies deployed have been classified into three major sub-classes, each consisting of four technology types.

Enabling Technologies:	Advanced Metering Infrastructure Meter Data Management Systems Telecommunications Supervisory Control and Data Acquisition
Demand Response:	In-Home Displays & Web Portals Demand Response Over AMI Prepaid Metering Interactive Thermal Storage
Distribution Automation:	Renewables Integration Smart Feeder Switching Advanced Volt/VAR Control Conservation Voltage Reduction

To demonstrate the value of implementing the Smart Grid, NRECA has prepared a series of single-topic studies to evaluate the merits of project activities. The study designs have been developed jointly by NRECA and DOE. This document is the final report on one of those topics.

DISCLAIMER
The views as expressed in this publication do not necessarily reflect the views of the U.S. Department of Energy or the United States Government.

ACKNOWLEDGMENTS

We are grateful for the input from the following, without which this report would not have been possible:

- James Bridges, VP of Engineering, Owen Electric Cooperative
- Steve Estes, System Engineer, EnergyUnited
- Bryan Jones, Distribution Engineer, Washington-St. Tammany Electric Cooperative
- Gerald Schmitz, Electrical Engineer, Adams-Columbia Electric Cooperative
- Michael Milligan, Manager of Engineering, Snapping Shoals Electric Membership Corporation
- Timothy Sharp, COO, Salt River Electric Cooperative
- Craig Thompson, Partner, Thompson Engineering
- James Thompson, General Manager, Adams Electric Cooperative
- Brad Wilson, Manager of Engineering, Clarke Electric Cooperative

ABSTRACT

This report discusses the deployment experience at nine rural electrical cooperative utilities of distribution automation technologies applied to Smart Feeder Switching (SFS) applications. We investigate the suitability of models to represent and predict the benefits of these technologies, with extensions to automating screening and engineering analysis for future deployments. This study defines an analytical methodology for quantifying the value of two SFS operational benefits: (1) more rapid restoration following a fault and (2) reduced I^2R losses through feeder load balancing. It also conveys a listing of SFS benefits and costs, identifying those deemed to have first order impacts, and compares projected values with field study results from National Rural Electric Cooperative Association (NRECA) Smart Grid Demonstration Project participants. In addition, it defines a logical modeling framework and analytics process for evaluating costs and benefits.

EXECUTIVE SUMMARY OF RESULTS

1. Gaining experience with increasingly prevalent distribution automation technology was an important driver behind cooperative participation in these demonstrations.
2. Non-labor costs were consistent per automated switch, but costs per customer average interruption duration index (CAIDI) minute of improvement, when calculable, were variable due to the diverse system types under study.
3. Multiple cooperatives were able to bring large percentages (30%–50%) of their feeders into configurations that enabled self-healing through back-feeds and automatic source transfers.

RESEARCH QUESTIONS

- **Field Trials:**
  - In the co-ops that installed hardware, what were the expected and realized benefits for reliability and feeder balance?
  - What are best practices and common “gotchas” across all deployments?
  - How do the benefits accrue to the cooperative, co-op members, and upstream power providers?
  - What are the impacts of these technologies on maintenance efforts?
- **Model Extensions:**
  - Can we accurately represent reliability impacts of smart feeder switching technologies via powerflow models?
  - What feeder characteristics are correlated with what benefits, and can this information lead to a system screener to locate candidates for technology installation?

TECHNOLOGY DESCRIPTION

Smart Feeder Switching (SFS) employs hardware, software, and procedural components to perform automated switching actions on distribution feeder systems. It creates (1) a “self-healing” system that can locate and isolate faults and automatically restore service, and (2) a more efficient network that reduces distribution system losses through load balancing across feeders.

Distribution feeders can be designed in a loop or radial configuration. Loop configurations have more than one power source, whereas radial configurations have a single power source. Radial feeder design typically is used for feeders covering large geographic areas in remote locations.

Utilities usually design feeders in loop configurations, when economically feasible. A loop configuration allows utilities to restore power from another source in the event of a system fault.

Automated Fault Location, Isolation, and Restoration (FLIR)

In general, utilities have not implemented SFS systems at distribution-level voltages; therefore, system operators usually do not monitor the distribution system. When customers lose power due to a fault on a distribution line, utility operators usually are not aware of the service interruption until they receive a customer call. It can take several hours for utility crews to determine the fault location once they are dispatched. SFS enables remote monitoring of distribution system equipment and automates the fault location, isolation, and restoration processes so that electric service usually can be restored in minutes.

Feeder Switching for Load Balancing

Feeder switching for load balancing is the process of transferring loads from one feeder to another to balance the total load across multiple feeders and transformers, thus reducing line losses, calculated as the square of line current.

FIELD DEPLOYMENTS

Nine cooperatives completed SFS projects. Descriptions of the deployments follow.

Adams Electric Cooperative

Motivation

Adams Electric Cooperative (AEC) is a utility serving 8,500 members around Camp Point, Illinois (see **Figure 1**). The cooperative undertook this grant-funded project to better serve its members and leverage existing technology. A key goal was to improve restoration times when members are faced with an outage by automatically switching members to an alternate feed without any human intervention. This technology improves members' ability to keep their businesses operating.

Installation Description

As part of its SFS activity, AEC installed 2 distribution switch controllers, 2 distribution reclosers with panels, 18 distribution fault detectors, and 2 overhead switches. The two automatic switches were deployed in a heavily loaded area on the east side of Quincy, Illinois.

Total project hardware and software cost for communications, supervisory control and data acquisition (SCADA), and switching hardware was $190,000.

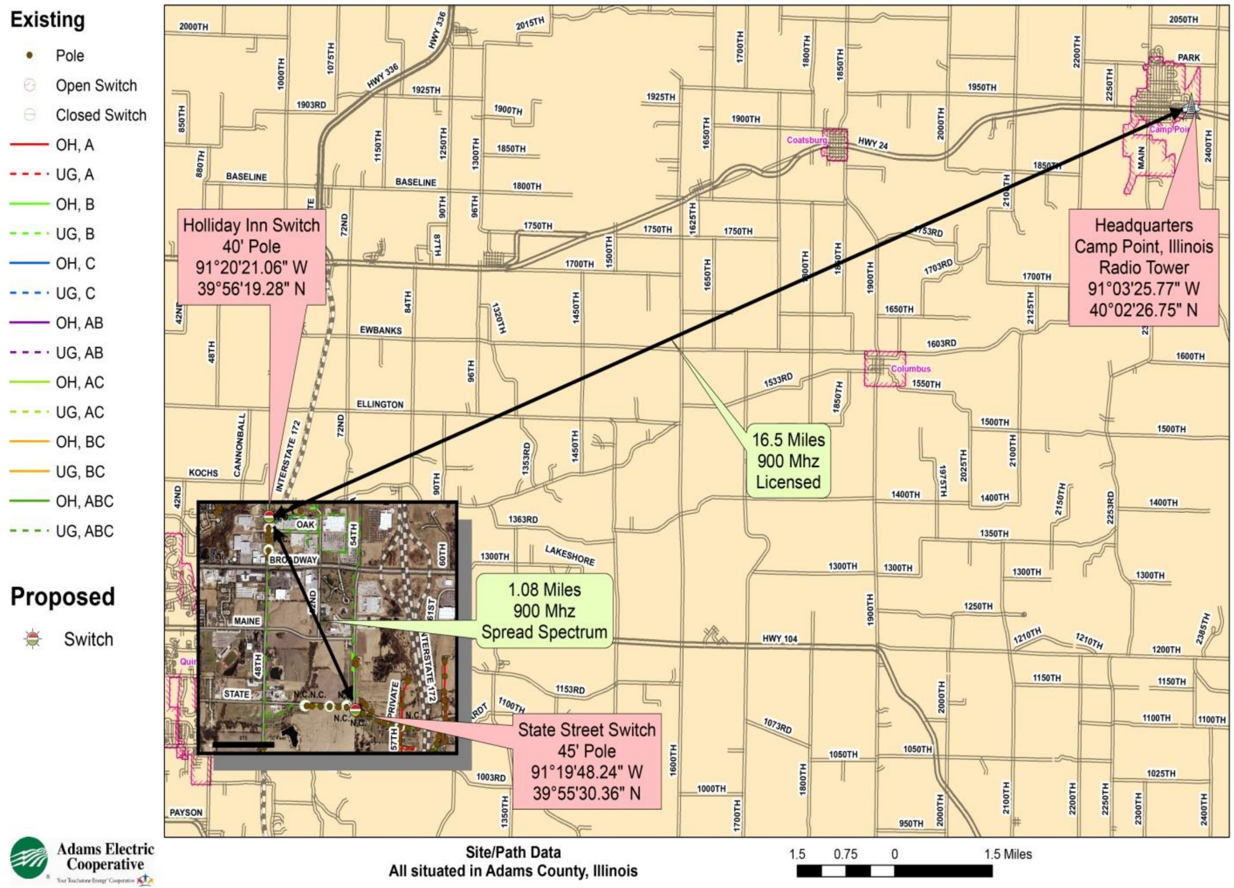

Figure 1. AEC Communications System Design and Switch Sites

Planning Experience

Engineering planning began with D/A switch site selection. Due to its St. Anthony West feeder's heavy commercial loads, the cooperative considers it an area of critical importance. The project was designed such that, if the St. Anthony West's normal feed was lost, the St. Anthony North feeder would pick up this area as an alternate feed. AEC prefers overhead D/A switches over underground D/A switches due to ease of install, cost, and configuration safety. With this in mind, AEC determined physical D/A switch placement using geographic information system (GIS) maps and a site visit, taking pole placement and normal opens into consideration.

A fault magnitude (coordination study) was performed to determine the settings necessary in the D/A controls for proper operation of the D/A switches. AEC had to determine the time-current curves, pick-up, and number of operations in all of the over-current devices up- and down-line of the D/A switches. This was achieved via a Milsoft Windmil model, device TCC specifications, and a coordination work sheet.

The cooperative also performed a coordination study to determine proper programming for the D/A switches, given system conditions and programming of existing 6801 control fields. Engineering and operations personnel reviewed all of the 6801 control fields, considering, for example, using the D/A switch to act as an over-current device that would open before the substation Nova reclosers would go to lock-out, and not allowing the alternate feed to close into a fault if a fault was present in between the D/A switches. AEC took into account programming that would minimize the outage time and assist in troubleshooting the outage.

A communication propagation study also was required. A line-of-sight study via GIS maps was conducted to determine the height of the AEC master radio antenna and the distance to the north D/A switch. This also provided the distance and height of the north and south D/A switches. On-site RSS tests were conducted using a 30’ test MDS 9710 SCADA radio and antenna located at the proposed north D/A switch site. A received signal strength indicator (RSSI) reading of 80Db from AEC’s master SCADA radio was considered more than adequate for reliable SCADA communication. No in-house equipment was available to test the peer-to-peer RSS, so AEC used the following method to determine whether a reliable peer-to-peer communication could be established: two bucket trucks were raised to a height of 30’ to establish that a clear line of sight between the two peer-to-peer locations was available and the span did not exceed the distance limits of the two radios per S&C specifications.

Deployment Status

The installation of the distribution automation switches was completed in May 2012, and the system has been active since then.

Deployment Lessons Learned

AEC had no problems with installing and bringing the SCADA communication on line. However, with peer-to-peer communication, there was an issue with radio frequency (RF) interference from the Holiday Inn building in proximity to the north D/A switch. This required moving the peer-to-peer antenna one pole span to the south. It was not foreseen that RF interference would be a problem in the original location.

The S&C automatic controllers are functioning correctly but, in the start-up process, AEC had some difficulty in programming the controllers due to manufacturing problems: the wrong firmware was installed in the controllers.

Schweitzer underground and overhead fault indicators were easy to install and met the cooperative's needs. It is foreseen that these indicators will help with trouble shooting faults.

Realized Benefits

The cooperative has not experienced any faults, loss of voltage, single phasing, etc. on the distribution system where the distribution automation switches have been installed. Even though the switches have not yet operated, installing them and learning about their capabilities has improved the resiliency of the distribution system and provided experience to AEC engineers for future distribution automation projects.

Adams-Columbia Cooperative

Motivation

Adams-Columbia Cooperative (ACEC) is a cooperatively owned utility serving 36,000 members around Friendship, Wisconsin. ACEC's service territory was hit by severe storms in 2001, which led to making system resiliency a priority.

Installation Description

ACEC installed 10 distribution reclosers—4 overhead and 6 underground. All reclosers were outfitted with automatic controls and communications capabilities. The SCADA system also installed as part of the Smart Grid Demonstration is the point of control for these smart switches.

Although the reclosers can be human operated remotely, their role in the smart switching scheme is to report back system conditions to SCADA and then take orders to reconfigure the system from the smart grid software (Yukon Feeder Automation).

The utility's feeders are all in radial configurations. Currently, a limited amount of back-feeding is possible through switches normally open. This project increases the number of interconnection points and hence opportunities for power restoration in fault conditions.

Total hardware and software costs for this project were $414,000, which breaks down as follows (**Table 1**):

Table 1. ACEC Hardware and Software Costs

Hardware Description	Quantity	Unit Cost	Extd Cost
OH distribution switches with controls	4	$22,792	$91,168
Underground switches with controls	6	$39,970	$239,820
Radio communication equipment, 5.8 Ghz	2	$2,245	$4,491
Radio communication equipment, 900 MHz	13	$2,245	$29,191
Radio communication equipment, 200 MHz	9	$2,245	$20,209
		Eqpt Cost	$384,878
		Shipping (2%)	$7,698
		Sales Tax (5.5%)	$21,592
		TOTAL HW/SW	**$414,168**

New switch locations relative to substations are shown in **Figure 2**.

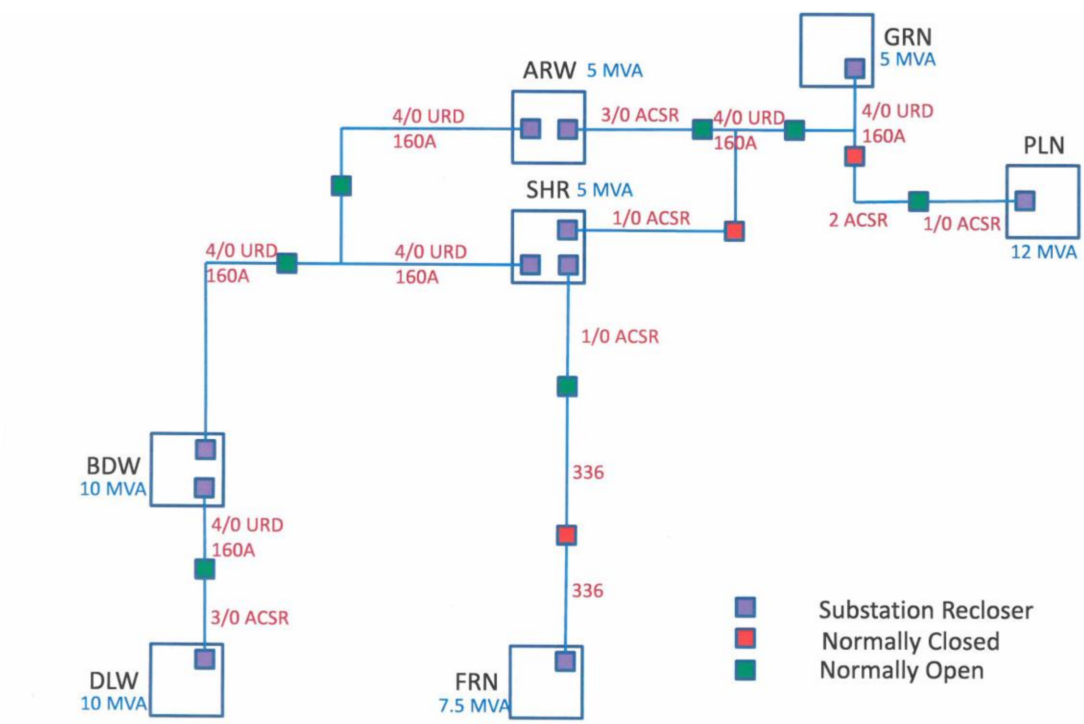

Figure 2. ACEC Substation Map with New Connectivity and Switch Settings

Deployment Status

All hardware has been deployed as of November 1, 2013. The system passed a brief outage test—when the test recloser was opened, feeders reconfigured as designed.

The system is expected to operate once a year when it is ready, so data volume for verification and resiliency benefit estimation is expected only after many years of system operation. There is a possibility of field testing with additional induced faults.

Clarke Electric Cooperative

Motivation

Clarke Electric Cooperative is a utility serving 5,200 customers in portions of eight counties in South Central Iowa. The primary motivation for this project was to improve operational efficiency for the cooperative and increase reliability for the members.

Installation Description

The SFS activity includes distribution switches/controllers at 21 field switch locations, distribution reclosers and automation equipment at 33 locations, and monitoring and control software.

The communications activity involved design and installation of radio backhaul equipment and associated communications equipment to link Clarke's control center with DA at the 54 remote locations.

An additional SCADA activity was intended for the installation of both hardware and software for a small-scale SCADA system, which supports the smart feeder activity. In addition, Distribution Fault Anticipator monitors will be installed on all three feeders at one substation. This equipment and software will help determine potential distribution hardware that needs to be addressed. This will improve power delivery reliability and information transfer accuracy.

Deployment Status

Installation is complete and the hardware is functioning correctly in the field.

Lessons Learned

Brad Wilson, engineering manager at Clarke EC, shared his lessons learned: "Understand zoning and ordinances for the placement of towers. We had to relocate a tower that was installed too close to a roadway, assure that the engineering consultant is intimately familiar with the specific technology being implemented, and plan for extensive training for internal personnel. In fact, the internal personnel need to be involved in the installation and setup of the system if they will be assuming ownership after the project is completed."

Realized Benefits

Clarke has implemented a self-healing scheme with the project switches that performs within minutes what were previously 4 hours of manual switching procedures. Both DA switches and electronically controlled reclosers operate in a sequence to restore service to feeders served from one substation, which had a history of transmission reliability issues.

The cooperative also has received some benefit from having switches that can be remotely operated instead of requiring a truck roll. Utilization of these capabilities, as well as the self-healing scheme, will increase as operational experience increases and engineering analysis continues. Clarke looks forward to adding more "brains" into the control software of these smart devices in the future.

EnergyUnited

Motivation

EnergyUnited (EU) is a cooperatively owned utility serving 121,000 customers around Statesville, North Carolina.

One of EU's top corporate goals is service reliability. Its current reliability rating is 99.98, but it is focusing on smart grid technologies with the intent of improving reliability for members as well as increasing overall efficiency.

Since EU's electric service area spans 19 counties throughout North Carolina, travel time sometimes increases the time required to complete restoration. For this reason, EU piloted an SFS project to test and demonstrate how this smart grid technology can increase reliability for members.

Installation Description

Currently EU has a 12.5 kV delivery, known as the Boomer Delivery. From this delivery, it has one circuit coming out, known as the Boomer Circuit. This circuit goes for several miles and is located at the far end of its service territory. When power is lost from its service provider, it can take a considerable amount of time for a crew to reach the site. Once service crews are at the site and have determined that the outage is caused by a loss of the source, EU may back-feed this circuit from another substation and circuit located approximately 8.5 miles away. Because the back-feed is a fairly good distance from the Boomer Delivery, there is a limit as to how much of the circuit can be back-fed. During lightly loaded periods, the entire circuit can be back-fed. During more heavily loaded periods, EU can back-feed only a portion of the circuit. It can take between an hour to 3 hours for crews to complete this back-feed and restore power to our members. The Boomer Delivery is located at the end of a fairly long circuit owned by Duke Energy. Because there is such a long distribution feeder serving this delivery, outages of the source are not uncommon.

To provide greater reliability to members, EU proposed automating this back-feed using distribution automation and the existing SCADA system. The automated system monitors the loading on the circuit at all times. A monitoring system is placed at the source of the delivery to sense a loss of source. In that event, the automated system determines the loading at the time just before the outage occurred. Based on this information, the automated system determines if the entire circuit, or only a portion, can be back-fed. Depending on the outcome of this decision, the automated system operates a series of 2 reclosers and 3 switches out on the circuit and completes the appropriate back-feed. Once power is restored to the source and EU has confirmed with the delivery provider that the outage is over, EU personnel trigger the system to undo the back-feed and return the circuit to normal operation.

Automating the back-feed system takes what typically would have been a 1- to 3-hour outage and reduces it to less than 5 minutes in most cases.

Total smart feeder switching project cost was $214,000, of which $138,000 was hardware and software purchased for the activity. **Figure 3** shows EU’s one-line diagram.

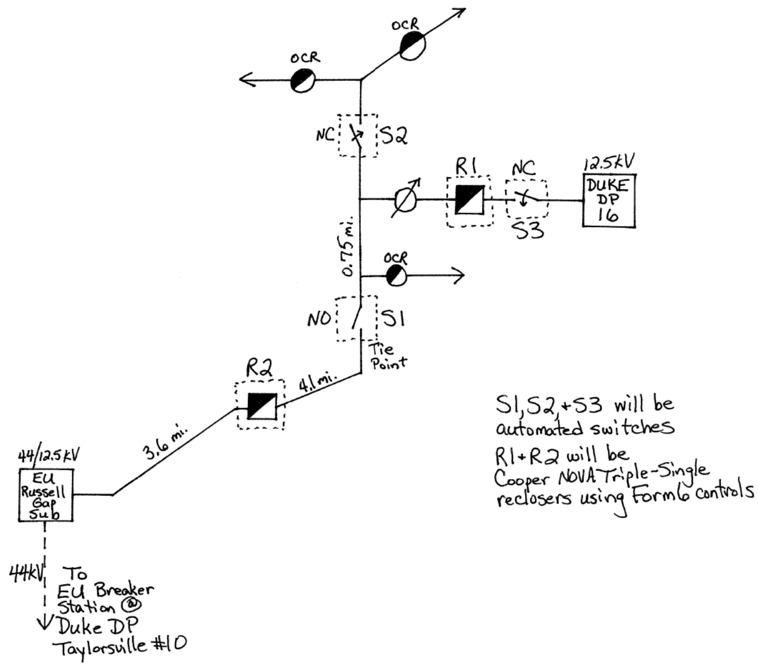

Figure 3. EU Project One-Line Diagram

Planning Experience

EU requires a business case for all projects outside the scope of routine business operations and with costs greater than $ 1,000.

There were two key drivers for the project in the business plan. One was the recognition that distribution automation systems are increasingly commonplace and that there is a need to test and build expertise in operating these systems. The second driver was the frequent source outages on the remote Boomer feeder: "…automated switching system would eliminate the need for crews to travel to Boomer and would reduce the outage time to almost nothing. In the last 5 years, this delivery point has been out a total of almost 45 hours. Through the existing back-feed process, EU crews have been able to cut that to less than half. The proposed distribution automation system would have reduced that to a little over 3 hours. CMI (Customer Minutes Interrupted) would be reduced by 90%... Based on an outage history over the last 5 years, we estimate that this project will save approximately 0.75 CAIDI minutes per year. At a total project cost of $250,000, this equates to a cost per CAIDI minute of $333,000." [9]

Communications were seen as a particular challenge: hills and rugged terrain make line-of-sight communications difficult and existing communications infrastructure is sparse.

Deployment Status

EU is finishing the installation, with an expected completion date in mid-November 2013. All hardware has been delivered, and EU is in the process of changing some poles out and installing switches and other equipment. Once that is complete, Siemens will complete installation of the controllers and commission the system.

Deployment Lessons Learned

"Communications paths are the most critical element. The switching schemes and logic is actually a fairly simple thing. The real key is making sure all the devices can communicate well." [10]

Kotzebue Electric Association

Motivation

Kotzebue Electric Association (KEA) is a cooperatively owned utility serving 1,264 customers around Kotzebue, Alaska. Its distribution system is not connected to the North American grid, and it operates all of its own generation assets. Because of this, it faces black-start situations atypical of those found at most distribution cooperatives.

Kotzebue frequently experiences temperatures below 40 degrees Fahrenheit and winds in excess of 50 MPH. Due to these conditions, even routine distribution system maintenance is difficult and places linemen at risk.

As rural residents in northwestern Alaska, KEA consumer-members face some of the highest costs anywhere in the nation. In 2008, residential power rates in the region varied from $.48/kWh in Kotzebue (up from $.39/kWh in 2007). KEA is working to implement long-term energy options, which currently include battery storage and 3 MW of wind generation, to assist its members in reducing their energy requirements.

Installation Description

KEA extended its use of automatic feeder switching capabilities with two pad mount, SCADA-controlled switches. This project doubled the number of automated switches at the utility, bringing all four feeders in the system under remote control.

The additional switches allow for sectionalizing in response to construction and maintenance needs. They also provide load shedding capabilities that do not require manual intervention by work crews. In the case of a black-start of the system, remote control of all four feeders allows easier service restoration and better power quality for consumers (due to reduced inrush currents), as each half of the load in the system can now be brought up individually.

Total smart feeder switching project cost was $333,000, of which $308,000 was hardware and software purchased for the activity.

The additional switches (numbers 3 and 4) are indicated in **Figures 4** and **5**, the system's one-line diagrams.

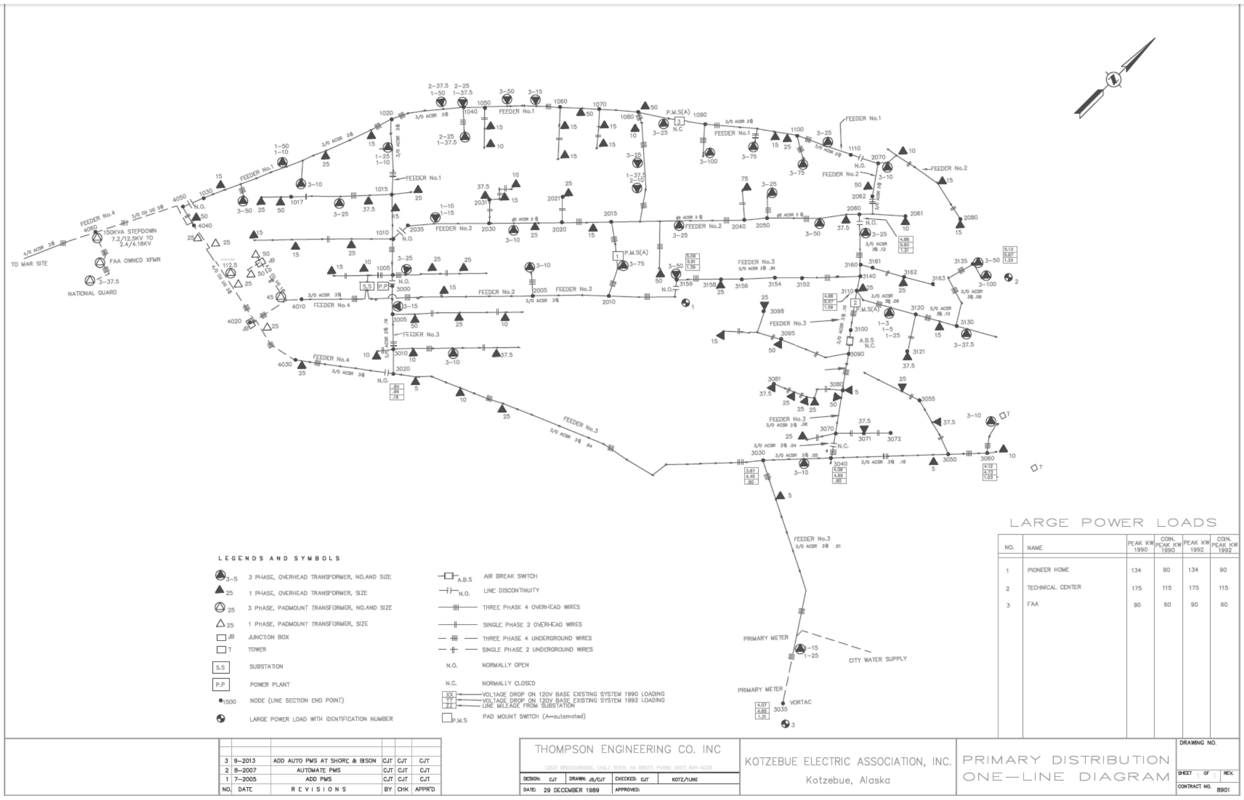

Figure 4. KEA Primary Distribution One-Line Diagram

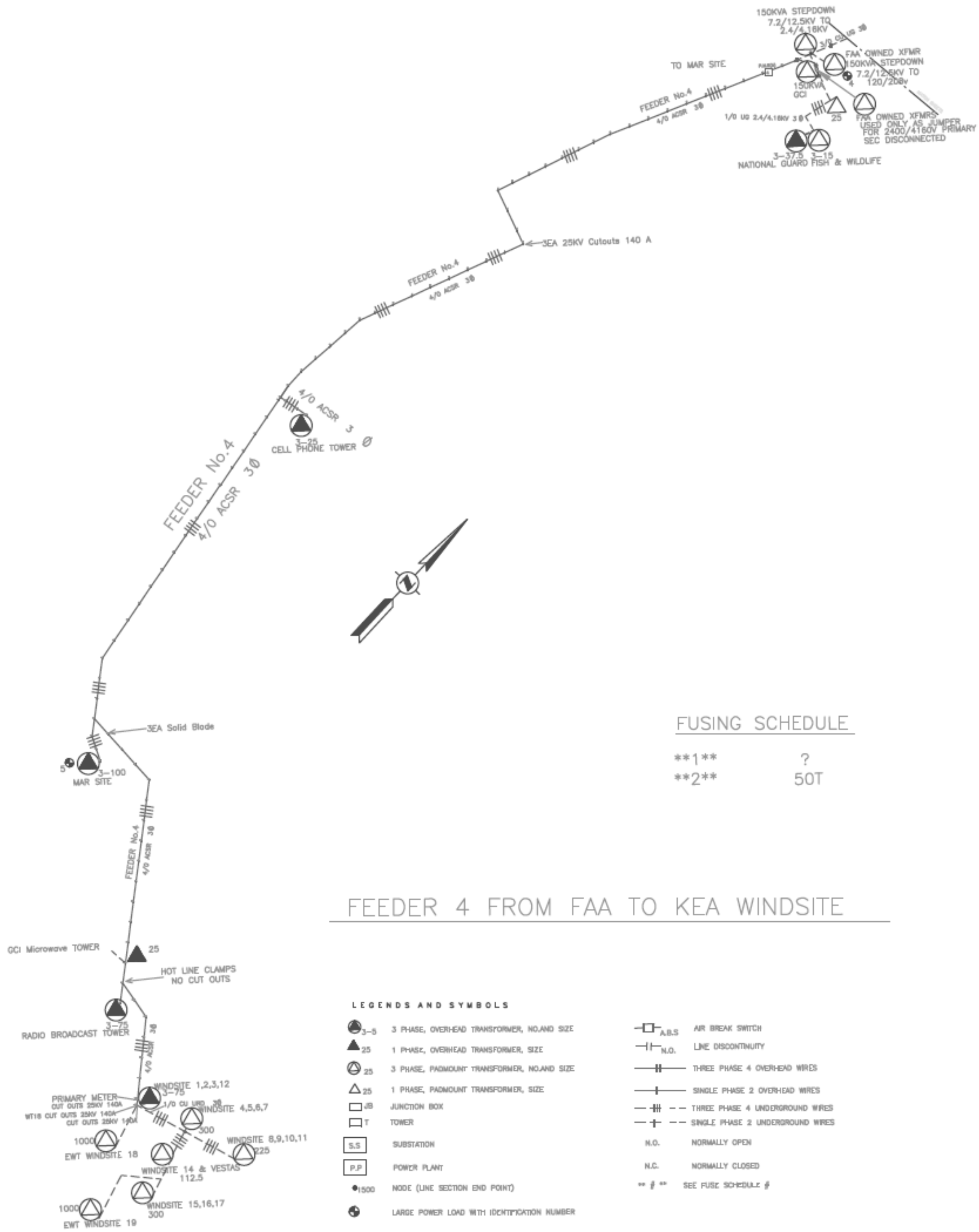

Figure 5. KEA Feeder 4 One-Line Diagram

Planning Experience

The original engineering design for this project was done in 2003 for a Rural Utilities Service (RUS)-funded installation of the original two pad mount switches.

Deployment Status

All hardware is deployed, tested, and operating correctly.

Owen Electric Cooperative

Owen Electric Cooperative is a utility serving 57,462 consumer-members around Owenton, Kentucky.

This smart feeder switching project aimed to provide redundant power to a municipal sewage treatment plan. Due to EPA regulations, the plant requires a highly reliable power supply to avoid negative environmental impacts that could result from plant shutdown. Owen could offer this capability more cheaply than backup generation by providing access to a second feeder source activated instantly via smart feeder switching.

Installation Description

Owen's SFS activity was targeted at two sites that will be able to automatically switch load using communication, switches, fault indicators and controls. In support, communications infrastructure was upgraded, including licensed fiber/microwave communications links between the Fulsom and Walton substations, and radio equipment was installed at 42 sites as support for this and other activities.

Total project costs for hardware and software were $107,000.

Planning Experience

Previous experience with automatic source transfer on a remote feeder serving a large residential subdivision provided the inspiration for this project. Multiple automatic service restoration events were achieved on this previous project, and telemetry capabilities have also been used to assist in other restoration events.

Deployment Status

The project hardware has been installed and in operation for over one year.

One source loss occurred during a period of high load. The switching system was not able to automatically restore service. When hardware was returned to the manufacturer for service, mechanical switch problems and a damaged control circuit board were discovered. The sewage treatment plant did lose power, but the outage was such that no regulatory fines were incurred.

Salt River Electric

Motivation

Salt River Electric is a utility serving 47,411 consumer-members around Bardstown, Kentucky. Salt River found that a majority of its outages in 2009 and 2010 were due to source losses at substations, due to transmission problems. Lacking direct control at the transmission level, the cooperative sought a method to improve reliability for its customers through smart feeder switching and redundant transmission sources.

Installation Description

The Smart Feeder activity includes the installation of 29 S&C IntelliRupter distribution switches with controllers. Also included in this activity is communications equipment required to make this equipment work.

A total of 25 switches were installed at normal opens between pairs of feeders in Salt River's system. Out of 100 circuits, 50 are now connected via this project hardware. In these 50 linked circuits, should an outage occur on either feeder or substation, the switches are configured to automatically back-feed from unaffected circuits, if feasible. This involves an automatic testing protocol, including voltage-based load testing and test reclosing operations. Delays of 2.5 minutes have been added to these automated switching operations to keep the switches from fighting other equipment, notably control systems at the transmission level. Switches also are able to be operator controlled remotely via SCADA.

Four additional switches were installed to create a looped circuit. These switches are intended for fault isolation.

Circuits for this project were selected based on historical load from all seasons. Pairs were selected for smart feeder switching in cases where the engineers were confident that each circuit could back-feed the other regardless of load level. Additional pairs of circuits could have been joined, but during times of high load, back-feed could not be guaranteed.

The total project cost is $1.32 million, of which $817,000 is hardware and software purchased for the activity.

Deployment Status

The system has been installed and operational since mid-2012.

Lessons Learned

Out of 29 switches installed, four had hardware or software problems that required vendor intervention. It was also found that the automation potential of the switches was excellent, but this also led to a lengthy and complicated configuration process. The software interface for this process is a potential area of improvement.

Realized Benefits

These switches also are useful for maintenance and sectionalizing. Co-op engineers estimated that they are used for these purposes once every 3 days. The co-op staff also appreciates automatic restoration events that occur in the middle of the night, which previously would have required manual intervention.

Typical outage times before the system was active amounted to multiple hours. In instances in which the smart feeder switches operate, this time has been reduced to minutes. The System Average Interruption Duration Index (SAIDI) scores have been trending downward for the past couple of years at Salt River. A survey of recent outages and outage time saved due to the smart feeder switching follows.

Table 2. Salt River Post-Project Outages and Customer-Minutes Saved

Outage ID	Customers	Minutes Saved	Customer-Minutes Saved
1	671	33	22,143
2	450	45	20,250
3	800	43	34,400
4	498	60	29,880
5	222	150	33,300
6	18	90	1,620
7	358	180	64,440
8	1795	50	89,750
9	481	21	10,101
10	412	21	8,652
11	344	45	15,480
12	261	124	32,364
13	137	125	17,125

Table 2. Salt River Post-Project Outages and Customer-Minutes Saved (continued)

Outage ID	Customers	Minutes Saved	Customer-Minutes Saved
14	300	206	61,800
15	450	90	40,500
TOTAL			**481,805**

Snapping Shoals Electric Membership Corporation

Motivation

Snapping Shoals Electric Membership Corporation (SSEMC) is a utility serving 91,000 customers around Covington, Georgia. This project was undertaken to improve system reliability, maintenance, and operational capabilities.

Installation Description

SSEMC's SFS activity significantly upgraded feeder switching capabilities. Following the upgrade, which encompasses 100 new SCADA-controlled reclosers, SSEMC has approximately 31% (28,000+ meters) of its customers within a zone capable of automatic restoration, and all but a few substations can be switched out of service remotely. As part of the project, some work was done on upgrading the SCADA system to handle these automation-capable reclosers and adding some fiber optic communications runs and Ethernet radios to the required field reclosers as necessary.

Project hardware comprised 97 Cooper NOVA reclosers and 3 S&C IntelliRupter PulseClosers. A majority of the switches were deployed as pairs, protecting customers in an automatic source transfer (AST) scheme, while the rest are independently deployed at normally open points. The independent devices are not automated but serve two critical roles by (1) facilitating outage restorations for pairs of feeders and (2) potentially being used for preplanned switching. The communications backbone is mostly single-mode fiber. Some of the more remote devices are served with Ethernet radios. (See **Figure 6** for a map of SSEMC's AST regions.)

Total project cost is $4.11 million, of which $2.11 million is hardware and software purchased for the activity.

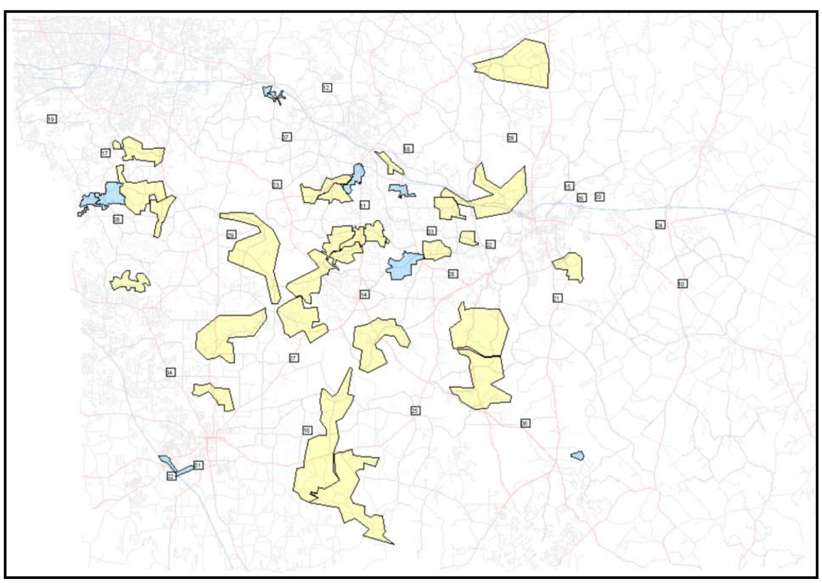

Figure 6. SSEMC AST Regions: Existing in Yellow, Project Additions in Blue

Planning Experience

SSEMC's first experience with smart feeder switching came in 2001. Following some outages to a large commercial customer, the cooperative decided to install an S&C Electric IntelliTeam AST system. This system detects outage on a primary feeder, switches load to a back-up feeder with no human intervention, and returns service to the primary feeder after power restoration. This technology has been a success, preventing 10 outages while serving up to 3 MW of load for approximately 60 customers over its past 12 years in service. However, the IntelliTeam system was not able to communicate with the SCADA system, limiting its operational potential.

In the years following this initial AST experience, SSEMC deployed several more schemes serving dense commercial zones, using controls that also were selected for the Smart Grid Demonstration Project. The new schemes were designed using a decentralized approach, with SCADA playing a supervisory role. The switching schemes restored power in much the same way as the original IntelliTeam, but they also updated SCADA after events happened and allowed the SCADA to take manual control when necessary.

Deployment Status

The hardware is deployed and the system was put into operation this year. Outage records and switching operations are being retained to quantify the value of the system.

Deployment Lessons Learned

From a distribution system employee's perspective, SFS can be scary. Most employees are not accustomed to working with technology that can automatically re-route power. Extensive training is required by some departments, but SSEMC encourages employees from all departments to attend. The results from the training have been fascinating, especially regarding employees who attend only because they are curious. Linemen initially had many questions about the safety aspects of automation. After training and experience with the system, they see how quickly narrowing down the scope of an outage reduces the pressure on line crews. The temptation to rush is reduced once most of the lights are on, thus enhancing safety. With participation comes better understanding, new ideas, acceptance, and results. What SSEMC has learned is that SFS is much more than technology. There is much more to learn, and the cooperative appreciates the opportunity that this grant has afforded.

SSEMC's system also is creating a great deal of outside interest, including an article in a recent issue of the trade journal Transmission and Distribution World [8]. Outside parties are most interested in how the cooperative has created a solution that goes beyond the individual components and demonstrates a comprehensive technology plan.

Realized Benefits

SCADA and switch automation used to assist with outage restorations has worked very well. Power can be restored safely, faster, and with fewer employees than before. In 2012, SSEMC experienced 16 events for which AST was used to address outages, thus preventing more than 11,000 consumer-hours of outage time. In five of those events, AST schemes automatically switched, preventing some customers from experiencing any service interruption. In that same year, more than 200 faults were automatically located. Most of those faults did not result in an outage, but the root cause was found about 75% of the time.

System maintenance also was improved, with savings realized through SFS. In spring 2013, several substations underwent routine testing, during which station unloading was accomplished quickly via remote switching. Normally, if everything goes as planned, testing is done during normal business hours with time to spare but, if there is a problem, restoring load can be delayed until after hours or even into the following day. In separate incidents, problems were discovered at two substations; it was after 10 p.m. before repairs were done on one of the stations, but dispatch was able to switch all 6 feeders back to normal from the office. Traditionally, this would have tied up a truck and one or two people at each open point on overtime, or the system would have been left as abnormal until the following day.

When problems were found on substations and the repairs pushed return switching past normal working hours, the new equipment saved man hours in switching the substation out of service via SCADA. However, the bulk of the benefit is the savings in crews and equipment on overtime, not just actively working, but also waiting on the repairs to be done for follow-up work.

The new equipment also has improved preplanned substation switching. Before the new equipment was installed, dispatch had to come to work at 6 a.m. to have a substation manually switched out of service by 8 a.m. for testing. With SCADA-enabled devices in place, the same switching can be done in about 30 minutes from the office.

Washington-St. Tammany Electric Cooperative

Motivation

Washington-St. Tammany Electric Cooperative (WSTE) is a utility serving 51,000 members north of New Orleans, Louisiana. The objective of this project was to improve the reliability of the system's transmission component, moving toward a self-healing capability. Hurricanes are a frequent hazard in the utility's service area, thus increasing the risk of large outages.

Installation Description

WSTE owns and operates 30 distribution substations served by 69 kV transmission lines. Unlike most cooperatives, WSTE owns transmission assets, including 180 miles of transmission lines. These, in turn, serve more than 5,000 miles of distribution line.

There are three components to the project—the SFS components, the SCADA system for control, and the supporting communications infrastructure. The communications infrastructure project includes fiber optic equipment at 14 substations. The SCADA system includes software and hardware requirements to implement advanced transmission and distribution automation projects. The SFS component involves installation of 24 transmission breaker relays and 27 transmission voltage monitoring systems in distribution substations.

Breaker relays are designed to operate in pairs to isolate faults, reclose in cases of momentary faults, and operate under SCADA control remotely. In concert with these capabilities, WSTE is closing the normal opens in its transmission network (see **Figure 7**). As a result, all substations will be served by 2 to 4 sources, and the long-term plan is to connect all substations in a heavily meshed network.

The total project cost is $6.36 million, of which $3.31 million comprises hardware and software purchased for the activity.

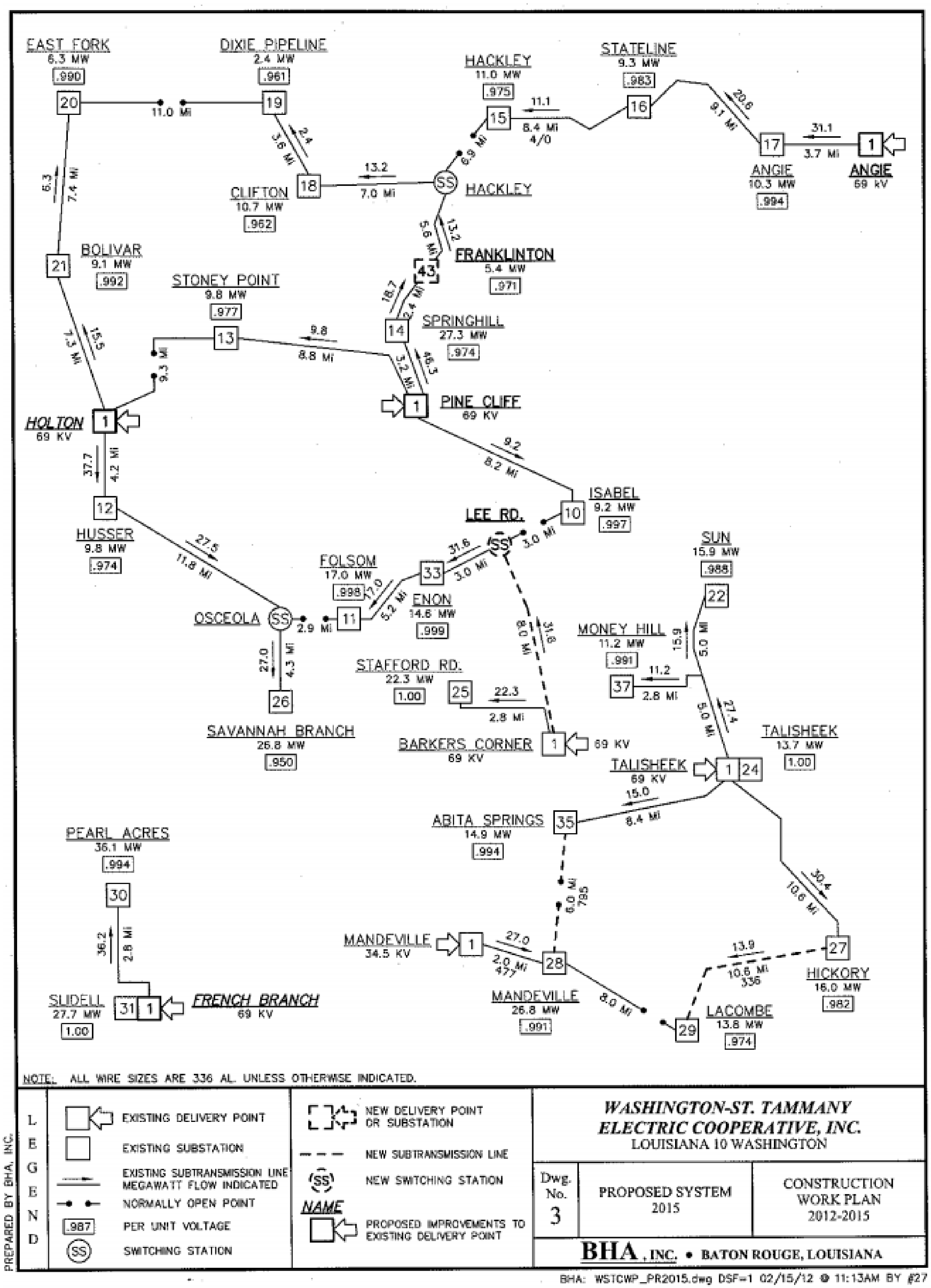

Figure 7. Washington-St. Tammany Transmission Network

Planning Experience

WSTE's transmission reliability strategy has been part of its engineering work plans for many years. In choosing to pursue upgrades of the transmission system instead of the distribution system, WSTE emphasized cutting down on transmission outages which, while rarer than distribution outages, affected more customers, since they cut off power to multiple substations. Furthermore, transmission faults on this rural system typically take line crews multiple hours to isolate and clear. When fully operational, the new automated switching scheme and multi-source transmission network will take the length of these outages from hours to less than a minute. SCADA and communications assets installed as part of this project will serve as a template for extending similar SFS capabilities to the distribution system.

Deployment Status

Deployment of the communications components of this project is ongoing and is expected to be completed by the end of 2013. During communications planning, a fiber optic option was found to be more economical than the original microwave/radio system, requiring schedule changes.

COST-BENEFIT METHODOLOGY

The following sections provide details about the SFS benefits and the cost methodology developed as part of this study.

SFS Benefits

SFS benefits were defined within three different domains. First, they were identified as deriving from either (1) Fault Location, Isolation, and Restoration; or (2) Feeder Switching for Load Balancing. Although these two functional areas both utilize switching, their control algorithms and grid impacts are quite different. Thus, this breakdown helped to determine the costs and benefits of each area.

Second, they were assigned to either a stakeholder category or, for benefits independent of a particular stakeholder group, to the "operational benefit" category. Each of these operational benefits can be baselined and measured easily. The first two domains are depicted in **Figure 8**.

Finally, benefits were categorized as having either first or second order impacts. First order impacts are considered to be the main drivers of SFS systems. **Tables 3** and **4** depict first and second order benefits, respectively, and also include parameters needed to calculate the benefit. Some benefit areas, such as reduced O&M costs, represent more than one sub-benefit group and need to be calculated separately and summed up at the end. Therefore, parameters needed to calculate each sub-benefit area also are listed in these tables.

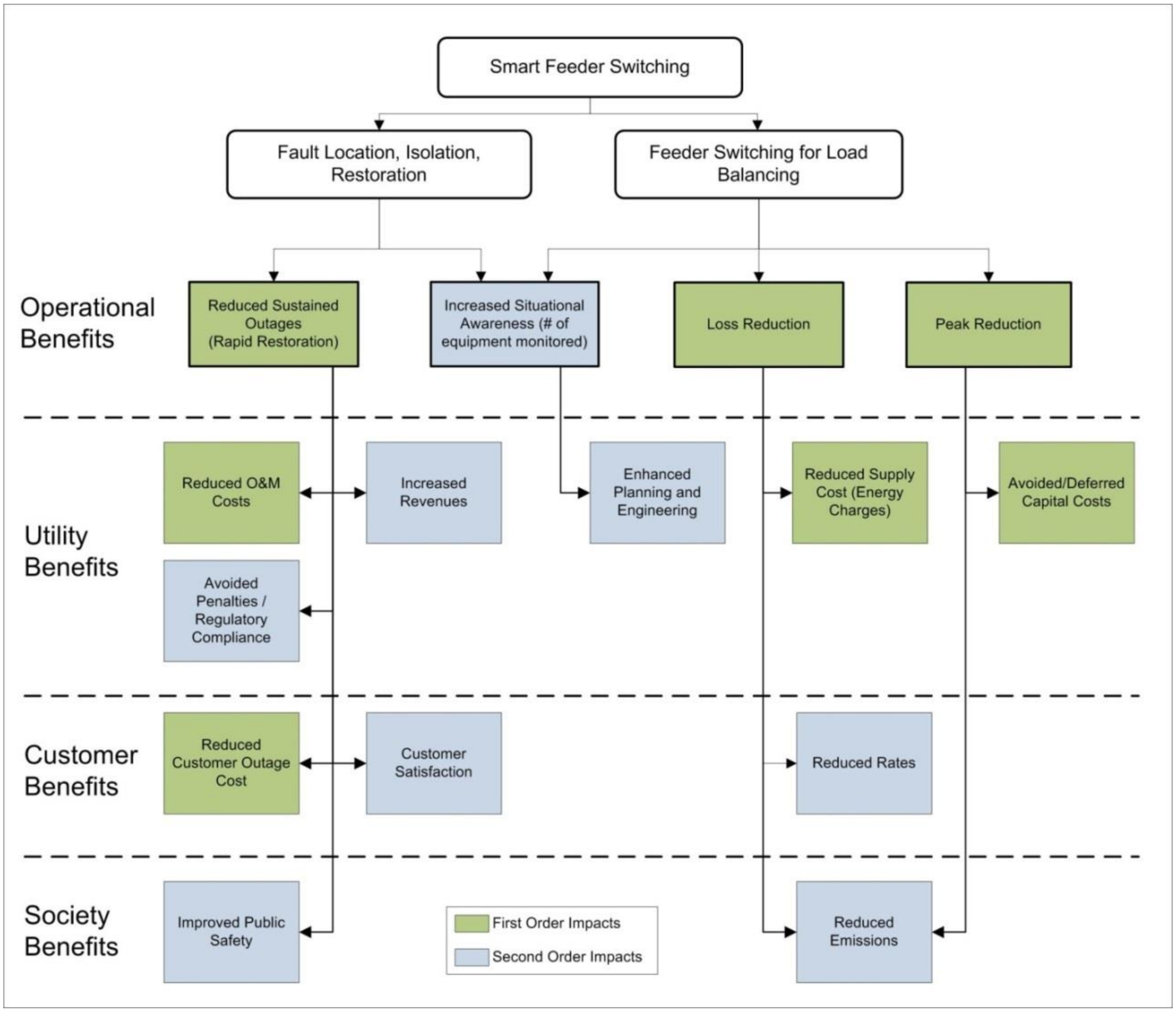

Figure 8. Smart Feeder Switching Benefits

Table 3. First Order Benefits

First Order Benefits	
Benefits	**Parameters**
Reduced O&M Costs	Annual FTE-hours avoided – Field Operations
	Annual FTE-hours avoided – Dispatch Center & Call Center
	Avoided vehicle costs
Reduced Customer Outage Cost	Avoided residential customer outage cost
	Avoided commercial customer outage cost
	Avoided industrial customer outage cost
Reduced Supply Cost (Energy Charges)	Avoided power supply cost
Deferred Capital Costs	Distribution capital investments deferred due to peak reduction

Table 4. Second Order Benefits

Second Order Benefits	
Benefits	**Parameters**
Increased Revenues	Utility additional energy sales as a result of reliability improvements
Avoided Penalties/Regulatory Compliance	Avoided penalties imposed by regulatory authorities due to SAIDI/CAIDI/SAIFI improvements
Customer Satisfaction	Improved customer satisfaction
Improved Public Safety	Improved public safety
Enhanced Planning and Engineering	Enhanced planning and engineering due to increased access to the field data
Reduced Rates	Reduced rates as a result of increased utility revenues
Reduced Emissions	Cap & trade cost
	Emissions reduced due to loss reduction
	Emissions reduced due to peak reduction

SFS Costs

Table 5 presents the capital and O&M costs typically incurred when implementing smart feeder switching. Exact costs depend on the size of the service territory or distribution infrastructure, level of existing automation, and state of existing IT and control systems.

Table 5. SFS Cost Categories

Cost Item	Cost Description
Distribution Infrastructure	Switchgear: reclosers, circuit breakers, load break switches, disconnect switches
	Sensors, current/potential transformers
IT and Control Systems	Supervisory control software
	IT infrastructure
	Automation hardware (IEDs, RTUs, PLCs)
Communications Equipment	Communications equipment
Engineering, Integration, and Testing	Engineering, integration, and testing
Annual Operations and Maintenance	Annual software maintenance cost
	Annual IT maintenance cost
	Annual automation maintenance cost

MODELING EXTENSION

The modeling framework to evaluate SFS systems is illustrated in Figure 9 and includes four main functional components: (1) User Input/Feeder Import, (2) SFS Model, (3) Solvers, and (4) Output Module. The proposed functionality of each block is described below.

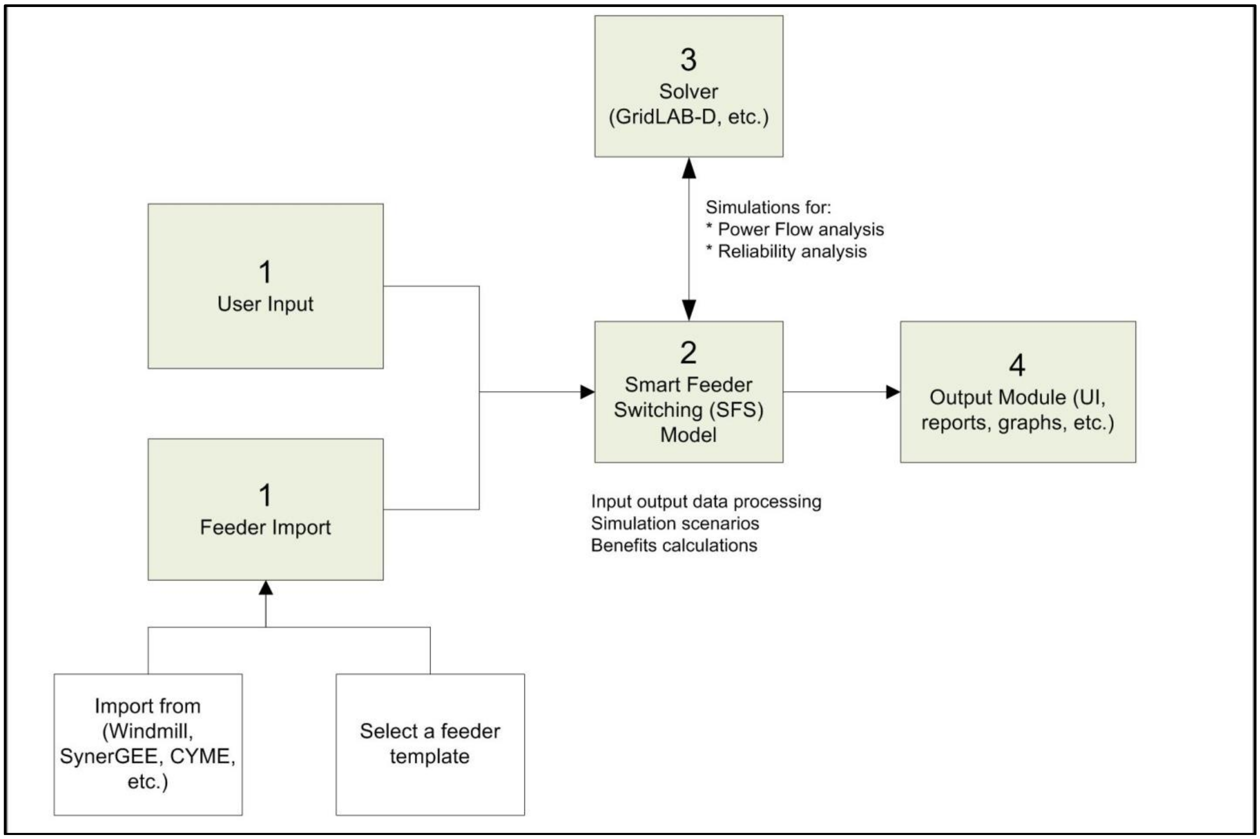

Figure 9. SFS Analysis Modeling Framework

User Input/Feeder Import: There are two types of inputs in this framework: user inputs and model import. User inputs include unit cost data, design parameters or preferences, financial parameters, feeder load data, and model configuration parameters, which are needed to perform cost and benefit calculations.

Feeder import is a specific feature that can be used to import distribution system models from commercially available software, such as Windmill, CYME, or SynerGEE. Utilizing these models will improve the accuracy of benefit estimations. It is also recommended to keep a library of typical distribution feeders in this model so that users may select a feeder that represents their system in case the distribution model is not available. Pacific Northwest National Laboratory (PNNL) has completed a Feeder Taxonomy project and has identified typical distribution feeders in the U.S. that can be leveraged in this effort.

- **SFS Model:** SFS Model is located at the core of this framework, where three main functions will be accomplished:
  - *Input/Output Data Processing:* Input data are converted to a format that solvers such as GridLAB-D can utilize. Output data are formatted for analysis reporting.
  - *Simulation scenarios:* User-defined scenarios will be simulated.
  - *Costs Calculations:* SFS Model will calculate costs based on user-provided data and default data available in its library. Cost calculation methodology is described in detail in the following sections.
  - **Benefits calculations:** Simulation results processed to calculate the monetary benefits listed in **Tables 2** and **3**.

- **Solvers:** Solvers include power system analysis software such as GridLAB-D, optimization engines such as CPLEX, and market simulation software such as PROMOD. It is expected that the majority of analysis can be done using GridLAB-D.
  - GridLAB-D is a power analysis software application with capabilities for modeling and simulating new smart grid technologies. The software has diverse functionality for running analyses on transmission, distribution, and market systems. We propose use of the Distribution Analysis module to perform time-series distribution load flow analysis and estimate the power loss and peak reduction, and the Reliability module to determine the improvements in reliability indices.
- **Output Module:** This module would generate tabular and graphical results, including inputs (design, financial, simulation parameters, etc.); derived inputs (customer outage costs, reduced losses, reliability indices, annual capital and O&M costs, etc.); annual costs/benefits in dollar amounts ($) and cost/benefit ratios (%); annual trend lines of reliability improvements/loss reductions/peak reductions; pie chart of cost/benefits; and bar chart of annual cost/benefits.

Cost Calculation Approach

The SFS analysis process will leverage the SFS deployment cost data that will be obtained from cooperatives, as they tend to be more accurate than generic integration and O&M cost estimates.

A proposed methodology for a cooperative to calculate SFS cost items is illustrated in **Figure 10**.

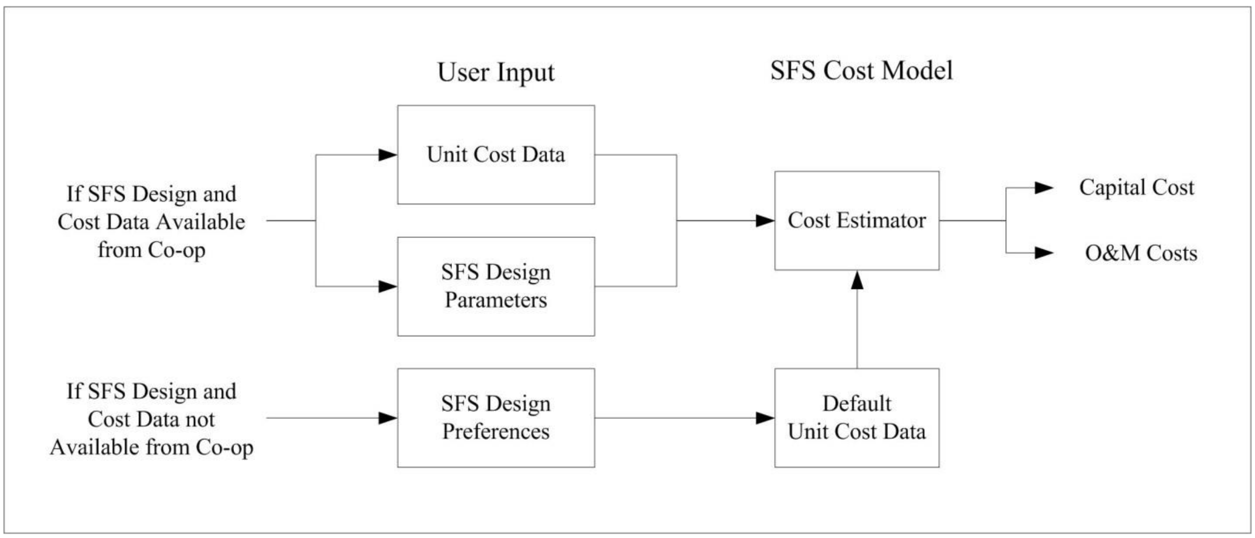

Figure 10. SFS Cost Calculation Methodology

In the case that unit cost data and proposed SFS design parameters are available, the user will be prompted to enter unit cost data, such as installed cost of reclosers, load break switch, etc. Necessary SFS system cost line items will be defined in the cost calculation tool. If a preliminary design already has been completed, the user will be able to enter design parameters, such as number of switches, type of switches, and type of communication system.

If the user does not have the unit cost data or preliminary design available, then a high-level cost estimate will be provided by the tool. To achieve this, the user will be asked to provide high-level design preferences. The cost model would include default unit cost data derived from cooperative-supplied cost data. The user will be able to select from this cost library to define the cost of specific devices.

User input cost and design data and default cost items will be used by the cost estimator to determine SFS solution capital and O&M costs.

Benefits Calculation Approach

The benefit analysis will entail both data calculations based on acquired performance data (in the case of peak load reduction) and more complex model simulation (as needed for loss reduction). The SFS analysis process will allow users to import industry-standard distribution system models from vendor products such as Windmill, CYME, and SynerGEE. This will enable the user to establish custom-tailored models that will closely resemble their distribution system parameters and obtain results relevant to their desired scenarios.

DATA REQUIREMENTS AND SOURCES

SFS Model Library

As described in previous sections, the SFS analysis process requires models that can be used to evaluate various deployment scenarios. **Table 6** outlines various data sets in the model library with the sources identified.

Table 6. Data Sets in the Model Library

Data Set	Source	Data Elements	Methodology
Distribution system feeder models	Co-ops	◆ Feeder models	Co-ops can upload their feeder models with feeder-type information (geographic, climatic, and feeder characteristics (length and capacity).
	PNNL	◆ Taxonomy feeder models	PNNL has developed 24 different sets of taxonomy feeders to represent a diversity of distribution feeder models comprising the U.S. distribution system.
Reliability improvements as a function of SFS design	Co-ops	◆ Co-op SFS design data for number, type, and location of SFS hardware components	Based on co-op's prior SFS deployment design and performance/reliability data, reliability improvements can be estimated as a function of SFS design.
	Co-op's ARRA reporting	◆ Baseline and post-deployment reliability indices (SAIDI, SAIFI, CAIDI, and MAIFI) ◆ Baseline and post-deployment outage data	
	External surveys/ literature	◆ Similar to above	External surveys and literature may be used.

Table 6. Data Sets in the Model Library (continued)

Data Set	Source	Data Elements	Methodology
Loss and peak reduction as a function of amount of transferred load	Co-op's ARRA reporting	◆ SFS event information (such as amount of load transfer, duration, etc.) ◆ Baseline and post-deployment 8760 feeder- loading data (kW, kVAR, kVA) ◆ Baseline and post-deployment equipment overload data ◆ Baseline and post-deployment distribution losses and power factor	Based on co-op's prior SFS deployment design and operational data, loss reduction/peak reduction can be estimated as a function of amount of transferred loads for various feeder types.
	External surveys/literature	◆ Similar to above	External surveys and literature will be used.
Customer outage costs as a function of reliability indices	Co-ops	◆ Residential customer outage cost ◆ Commercial customer outage cost ◆ Industrial customer outage cost	Calculate customer outage costs for various customer classifications.
	External surveys/literature	◆ Similar to above	External surveys and literature will be used.
	ICE Calculator	◆ Outage cost	DOE's Interruption Cost Estimate (ICE) calculator is an extensive tool for estimating the customer outage costs of various customer classifications. Estimation is based on several realistic assumptions and can be customizable for various geographic areas and different customer characteristics.
O&M cost reduction as a function of reliability indices	Co-op's ARRA reporting	◆ Baseline and post-deployment O&M costs	Calculate the reduction in O&M costs due to the SFS deployments.
	External surveys/literature	◆ Baseline and post-deployment O&M costs	External surveys and literatures will be used.
Financial Data	Co-ops	◆ Average annual retail energy rate (\$/kWh); average annual purchase power rate (\$/kWh); inflation rate; tax rate; GDP; average field, dispatch center, and call center operations labor rate (\$/hour); and expected life time of SFS project (years)	Calculate various financial factors listed.
	External surveys/literature	◆ Similar to above	External surveys and literature will be used.
Cost Data	Co-op's ARRA reporting	◆ T&D infrastructure costs, IT and control systems, communication hardware costs, and annual O&M costs	Calculate financial factors.
	External surveys/literature	◆ Similar to above	External surveys and literature will be used.

SFS Cost/Benefit Calculations

Once SFS models are built, users will need to provide certain input data to evaluate a given scenario. The users may also use the default data available in the model library. The complete set of data required to run the model is listed in Table 7.

Data Set Classifications:

- **Distribution System Characteristics:** This data set describes the state of a co-op's existing distribution system prior to SFS system deployment. If unknown, or if desired by the user, an appropriate predefined taxonomy feeder model from the model library can be used for analysis.
- **SFS Design Data:** Data related to the SFS project design, such as number, type, and physical location of SFS hardware components.
- **Financial Data:** Data describing co-op tariff and other financial information, such as wholesale/retail energy prices, average labor rates for various O&M activities, and average vehicle costs. The data set also includes other economic factors needed for net present value (NPV) of benefit calculations, such as inflation rate, tax rate, gross domestic product (GDP), and useful project life. If unknown, default values will be supplied by the model library.
- **Cost Data:** This data set consists of cost data for the elements specified in the above SFS costs section. If the cost details are unknown, the user can use the cost details available in the model library.
- **Future Capital Investments:** This data set captures future capacity expansion plans, such as substation transformer upgrades, distribution line reconductoring, and switchgear equipment upgrades.
- **GridLAB-D Simulation Scenario Inputs:** This data set consists of data required to run GridLAB-D simulations that produce expected SFS project results, including improvements in reliability indices, loss reduction, and peak reduction.
- **SFS project outcomes:** This data set is produced from GridLAB-D simulations and will be used in the cost-benefit model for monetizing benefits.

Table 7. Data Requirements of SFS Cost-Benefit Model

Data Classification	Data	Source	Usage
Distribution System Characteristics	◆ Study feeder models ◆ Performance and reliability data ◆ Operating and outage data ◆ Study feeders load profiles ◆ Study feeders load growth ◆ Customer classification (residential, commercial, and industrial)	Co-op (or) model library	Benefits monetization
SFS Design Data	◆ Number of project feeders ◆ Number, type, and location of SFS hardware components ◆ Type of communication ◆ Number, type, and location of communications hardware components	Co-op (or) model library	Cost estimation and benefits monetization

Table 7. Data Requirements of SFS Cost-Benefit Model (continued)

Data Classification	Data	Source	Usage
Financial Data	◆ Average annual retail energy rate ($/kWh) ◆ Average annual purchase power rate ($/kWh) ◆ Inflation rate ◆ Tax rate ◆ GDP ◆ Average field operations labor rate ($/hour) ◆ Average dispatch center and call center operations labor rate ($/hour) ◆ Average vehicle costs per fault location, isolation, and restoration event ◆ Expected life time of SFS project (years)	Co-op (or) model library	Cost estimation and benefits monetization
Cost Data	◆ T&D Infrastructure costs ◆ IT and control systems ◆ Communication hardware costs ◆ Annual O&M costs	Co-op (or) model library	Cost estimation
GridLAB-D Simulation Scenarios Inputs	◆ Updated feeder models with SFS design components ◆ Feeder switching sequence for load balancing event (switch positions) ◆ Feeder switching sequence for fault location, isolation, and restoration event (Switch positions) ◆ Event duration ◆ Event frequency (/yr) ◆ Device settings (substation transformer LTC, capacitor bank, etc.)	Co-op	Benefits monetization
SFS project outcomes	◆ Reliability indices improvements (SAIDI, CAIDI, and SAIFI) ◆ Loss reduction (kWh) ◆ Peak reduction (kW)	GridLAB-D simulations	Benefits monetization

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