Line Sensors for Distribution Automation: Practical Deployment, Data Collection and Use Cases

TAV Networks, Dayton Power & Light, and Pacific Gas & Electric
UU Course 202 - January 30, 2017
Distributech 2017
Instructors

Joe Tavormina
  • Comms & Sensors Systems: TAV Networks, Inc.

Jeff Teuscher
  • Distribution Ops Manager: Dayton Power & Light

Stan Thompson
  • Pilot Operations: Pacific Gas & Electric Company

Jared Hafer
  • Deployment Project Manager: Pacific Gas & Electric Company
Schedule

08:00 – Introduction to Line Sensors and Use Cases (15 minutes, Joe Tavormina)

08:15 – The Role of Line Sensors in Utility Operations (15 minutes, Jeff Teuscher)

08:30 – Theory and Operation of Line Sensors (30 minutes, Joe Tavormina)

09:00 – Use Case 1: Bracketing Fault Location (30 minutes, Stan Thompson)

09:30 – Use Case 2: Calculating Fault Location (30 minutes, Stan Thompson)

10:15 – Break (15 minutes)

10:15 – Use Case 3: Asset Management (15 minutes, Jeff Teuscher)

10:30 – Use Case 4: Power Quality Investigation (15 minutes, Jeff Teuscher)

10:45 – Use Case 5: Vegetation Management (15 minutes, Joe Tavormina)

11:00 – Planning and Executing a Deployment Project (45 minutes, Jared Hafer)

11:45 – Q&A (15 minutes)

12:00 – End
Content

• Line Sensors: in Distribution Automation
• Line Sensors: Operations and Communication
  • Current and Voltage sensing
  • Power harvesting, consumption, and management
  • Radio communications
• Deployment: Practical Aspects
  • Data management in today’s world of growing network security requirements
  • Use of Line Sensor data in today’s utility operations environment
  • Streamlining data presentation for system operators
• Based on real world Line Sensor projects at PG&E and DP&L
Purpose

• Provide attendees a basis for planning and executing Line Sensor projects
• Review intended business benefits needed to justify Line Sensor projects
• Discuss risks that are likely to be encountered during project execution
• Discuss integration into existing utility operational processes and application of data received from line sensors
• Share real-world challenges experienced and lessons learned in projects at:
  • Pacific Gas & Electric Company in California (PG&E)
  • Dayton Power and Light (DP&L) in Ohio
Objectives

• After taking this course the participant will be familiar with:
  • The practical use and deployment of Line Sensors
  • Business benefits that can realized using Line Sensors
  • Sensor data management, the use of cellular and mesh radio networks, radio coverage, and operation under low power conditions
  • Planning for both physical deployment and IT integration
  • “Lessons learned” from field deployments at PG&E & DP&L

• Be ready to mastermind a deployment project:
Introduction to Line Sensors and Use Cases

Joe Tavormina
Line Sensor Examples

Overhead
- Sentient Energy
- Tollgrade
- PG&E Experimental Voltage Sag Monitor

Underground
- Pad Mount Installation
- Surface Operable Vault Installation

Eaton
Grid-Sentry

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## Use Cases and Business Benefits

<table>
<thead>
<tr>
<th>Use Case</th>
<th>Business Benefits</th>
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</table>
| Fault Detection, Location, and Rapid Restoration  | • More rapid power restoration  
• More efficient use of restoration resources  
• Improvements in outage performance  
• Potential detection of high-impedance faults |
| • Readily identifiable and immediate benefits |                                                                     |
| • Direct impact on CAIDI and SAIDI metrics    |                                                                     |
| • Fault bracketing                            |                                                                     |
| • High-precision calculated fault location    |                                                                     |
| Power Quality Monitoring                      | • Data source for DMS and data historian                           |
| • Immediate use as an Distribution Planning tool |                                                                     |
| • Potential use as a dynamic feedback mechanism |                                                                     |
| Asset Management                              | • Situational awareness along extent of distribution lines  
• Verification of Recloser operation  
• Verification of Cap Bank integrity      |
| • Cost savings in Operations and Maintenance  |                                                                     |
| • Inexpensive form of substation automation   |                                                                     |
| Vegetation Management                         | • Condition-based vegetation management                             |
| • Experimental at this time – requires new analytics |                                                                     |
Adoption Decision 1: Cellular or Mesh Network?

• Cellular Network (Verizon, AT&T, Sprint, etc.):
  • Radio coverage (reliability from within pad mount cover?)
  • Long-term network support (2G, 3G, 4G, LTE, etc.)
  • Operational cost for bandwidth consumption

• Mesh Network (SSN, Cisco, Itron, etc. 900 MHz):
  • Radio coverage to battery-backed Radio Relay backhaul device
  • Latency and Traffic Capacity in a multi-hop mesh network
  • Capital cost for network deployment

• Other:
  • Satellite Communications (“Satcom”)
  • Wi-Fi
Adoption Decision 2: IT Strategy for Head End?

- **Use Case**
  - Sets requirements
- **Operator Interface**
  - Use of Existing and/or Additional GUI?
- **Data Repository**
  - DMS, Pi Historian, SCADA, or other?
- **Data Center**
  - In-House or Hosted?
- **Security Mandates**

PG&E IT Design for Tollgrade Line Sensor Pilot Deployment

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The Role of Line Sensors in Utility Operations

Jeff Teuscher
Sensor Roles on the Distribution System

- Fault location and magnitude recording
- Reduce field patrolling to location causes of line outages
- Power quality data can be captured and analyzed to predict future equipment failure through data trending
- Field equipment monitoring – lower cost alternative
- Sensors provide many data points for distribution system to analysis
- Circuit balancing tools
- Engineering Planning tools for quick access to line loading
- Alerts on reverse power flows
- Voltage sensing
Asset Management Functions

• Allow assets to be monitored real-time
• Track equipment operations to decide maintenance cycles
• Power quality data can be captured and analyzed to predict future equipment failure through data trending
• Sensor data can feed Distribution Management Systems for real-time modeling of the distribution system. Allows for optimization of the utility assets
• Sensors can provide many data points for asset systems to analyze
• Data is key to better analytics and this leads to better asset management
Hydraulic Recloser plus Line Sensor

• Cost Savings of $2000 per installation
  • Hydraulic Recloser + Sensor = $2500 + $1000 = $3500
  • Electronic Recloser = $5500

• Sensor will alert the operations center when it has operated and went to lockout

• Sensor will allow for tracking number of operations on the recloser

• Sensor will provide real-time amperage data to understand loading on the recloser
Sensors as an alternative to expensive distribution assets

• Hydraulic Recloser and Sensor vs Electronic Recloser
• Circuit Monitoring at Substation vs RTU and Digital Relays
• Planning Tools – Sensors Monitoring Load vs Load Logger Technology
• Monitor Capacitor Ground for current flow. Signals a blown fuse on the three phase bank.
• Monitor circuit balance at points along the circuit.
• Potential to use for vegetation growth. Based on small interruption or small current fluctuations.
• Fault detection and reporting on the distribution system
Sensors as Circuit Monitors at Substations

• Substations that do not have an RTU installed today.
• Sensors will be deployed on each circuit leaving the substation.
• Circuit monitoring can be achieved at much reduced cost. Sensors are Approximately $3500 per circuit installed.
• RTU with communications is approximately $50k - $75k before digital relays are installed.
• Sensor allows circuit loading, alert when circuit has operated, aggregate of circuit loads provides transformer loading.
• Sensors are monitoring only, where as RTU provides control at the substation.
Sensors as Planning Tools

- Sensors = $1000 each – Load Loggers are $1600 each
- Sensors provide data near real-time load data to the engineers
- Sensors don’t need batteries
- Load Loggers need to be installed for a period of time and then removed to retrieve the data
- Load logger needs software to download data
- Sensor supplies data to utility system of choice
Theory and Operation of Line Sensors

Joe Tavormina
Line Sensors provide most business benefits for a fraction of the cost

- Ease of installation
- Ease of integration into ADMS, SCADA and/or Historian
- “No” batteries included
- No need to roll trucks to read substation loads. Can be collected with the sensors.
- Ability to capture fault current events. Magnitude and duration.
- Ability to provide conductor line temperature – Dynamic Line rating.
- Monitor neutral current at capacitor banks – large currents show capacitor has blown one phase of the 3Φ bank.
Current Measurement

• Based on Rogowski coil
• Split ring permits installation on Distribution Line


Tollgrade LightHouse MV Current Sensor

Reference: Weiku.com
Voltage Measurement

• Direct voltage measurement at > 12 KV is expensive, and can pose safety risks
  • Example: Tollgrade MV Power Sensor

• Direct voltage measurement on transformer secondary can serve as a proxy
  • Examples: PG&E VSM, QNA LineWatch
Line Sensor Data Collection

- Event Driven
- Periodic measurements
  - Daily/hourly
  - Interval
  - Per phase
  - Current / EMF (Voltage)
- Other
  - Phase Identification (Automatic? Needs regional master reference unit)
  - Local readings from field measurements
  - Head-end setting/configuration

Cellular or Mesh Network backhaul:
- Verizon, AT&T, Sprint, etc.
- SSN, Cisco, Itron, etc. (900 MHz)

Phase angle measurements:
- See voltage and current waveforms not in phase
- Take corrective action (capacitors/inductors)
Example of Sensor Data on 4kV Circuit
Configuring Set Points and Alarms

• DNP3 points/mapping?
  • Identify what is delivered to DMS
  • ONLY fault data? (Minimal alerts)
  • Current load, phase imbalance, communications status, temperature, location changes and more are all configurable to send alerts to DMS
  • (very noisy/ false positives)

• Matching known trip settings?
  • Existing protective device settings
  • Feeder/device/load specific
  • Distribution engineer knowledge

• Outage timers?
  • Define sensor timer to allow for protective devices to operate
  • Typically ~60 seconds for reclosers to attempt 3
Communication Performance Factors

• Radio Network Coverage
  • Overhead Distribution
  • Underground Distribution
  • Statistical Modeling

• Power Consumption

• Quality of Service
  • Availability
  • Transmission Latency
  • Capacity
  • Reconnection Time

• Cost Factors
  • Capital Expenditure
  • Ongoing Data Transmission
  • Relative Deployment Costs

Antenna Gain is one of many factors that affects Communication Performance

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Overhead Communications

- Radio coverage improves by ~5 dB vs. ground coverage at typical 30-ft line height

This RF Test Rig was used to confirm RF Coverage at potential Line Sensor deployment locations

Measured RF Path Loss agrees with statistical predictions

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Underground Communications

• Radio coverage diminishes by 5-35 dB vs. ground coverage depending on local conditions
  • Earth grade
  • Composite or metallic vault covers?
• Special problems include flooding
Inductive Power Harvesting

• Applicable for Current Line Sensors

• Primary Current Requirements?
  • 6-12 amps for “normal” functionality
  • Typically employ super capacitors
  • NOT batteries
  • 3-6 amps minimum load to operate in “low power mode”
  • Different levels of functionality in low power?
  • May not capture waveforms in this mode
  • May not be able to query historical data

<table>
<thead>
<tr>
<th>BATTERIES</th>
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<tbody>
<tr>
<td>Pros</td>
<td>Cons</td>
</tr>
<tr>
<td>Power Density</td>
<td>Limited Cycle Life</td>
</tr>
<tr>
<td>Storage Capability</td>
<td>Voltage And Current Limitations</td>
</tr>
<tr>
<td>Better Leakage Current Than Capacitors</td>
<td>Long Charging Times</td>
</tr>
<tr>
<td>Constant Voltage That Can Be Turned Off And On</td>
<td>More Temperature Sensitive Than Capacitors</td>
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<tr>
<th>CAPACITORS</th>
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<tr>
<td>Pros</td>
<td>Cons</td>
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<tr>
<td>Long Cycle Life</td>
<td>Low Specific Energy</td>
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<tr>
<td>High Load Currents</td>
<td>Linear Discharge Voltage</td>
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<tr>
<td>Short Charging Times</td>
<td>High Self-Discharge</td>
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<tr>
<td>Excellent Temperature Performance</td>
<td>High Cost Per Watt</td>
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Power Harvesting Limitations

Debris in the magnetic jaw prevented this line sensor from properly harvesting power and recharging its battery.
Establishing Deployment Guidelines

• “Rules of Thumb” for deployment
  • Optimal spacing of Overhead mesh radio relays
  • Anticipated reliability of Overhead Cellular Data comms
  • Feasibility of Underground Cellular Data comms

• “First Pass” network design objectives
  • 95.0% or 99.5% coverage, and at what cost?
  • Coverage goals for Pilot Deployment projects may differ

• Power Harvesting Limitations
  • Average current at desired location

• Pre-installation Network Design / Field Survey process
## Product Comparison

<table>
<thead>
<tr>
<th></th>
<th>Tollgrade</th>
<th>Sentient</th>
<th>Eaton</th>
<th>Grid-Sentry</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Product</strong></td>
<td>LightHouse MV</td>
<td>MM3</td>
<td>GridAdvisor II</td>
<td>GS-200</td>
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<tr>
<td><strong>Fault Indication</strong></td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
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<td><strong>Current Measurement</strong></td>
<td>Average</td>
<td>Average/Max/Min</td>
<td>Nominal/Fault</td>
<td>Average/Max/Min</td>
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<td><strong>RMS Current Range</strong></td>
<td>3 or 6 - 600 A</td>
<td>6 or 12 - 800 A</td>
<td>3 - 600 A</td>
<td>10 - 1000 A</td>
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<td><strong>Max Voltage</strong></td>
<td>69 KV</td>
<td>90 KV</td>
<td>69 KV</td>
<td>138 KV</td>
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<td><strong>Harmonics Measurement</strong></td>
<td>Np</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
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<td><strong>Waveform Capture</strong></td>
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<td>Yes</td>
<td>No</td>
<td>Yes</td>
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<td><strong>Radio Communications</strong></td>
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<td>Cellular, Mesh, WiFi</td>
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<td>Cellular, Mesh, WiFi</td>
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<td><strong>SCADA Interface</strong></td>
<td>SMS or DNP3</td>
<td>DNP3</td>
<td>DNP3</td>
<td>DNP3</td>
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<td><strong>Operational Temp Range</strong></td>
<td>-40 to +60C</td>
<td>-40 to +85C</td>
<td>-40 to +85C</td>
<td>-40 to +65C</td>
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<tr>
<td><strong>Weight</strong></td>
<td>6 lbs.</td>
<td>6.5 lbs.</td>
<td>2.5 lbs.</td>
<td>3.5 lbs.</td>
</tr>
</tbody>
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Bracketing Fault Location

Stan Thompson
PG&E Company Profile

• Pacific Gas and Electric Company incorporated in California in 1905 based in San Francisco.

• Primary Business: The transmission and delivery of energy. PGE employs approximately 20,000 people.

• Goal: Establish the best operating Utilities in the U.S. Achieve the first quartile
• Service area stretches from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada in the east

• 141,215 circuit miles of electric distribution lines and 18,616 circuit miles of interconnected transmission lines

• 42,141 miles of natural gas distribution pipelines and 6,438 miles of transportation pipelines

• 5.4 million electric customer accounts

• 4.3 million natural gas accounts
PG&E Business Benefits from Line Sensors

Line sensors are a modern, cost-effective alternative to analog devices for detecting and locating electric distribution line faults, while also providing significant additional operational benefits.

1. Reduce cost of outage response

2. Increased system reliability

3. Assessment of line sensor capabilities
PG&E Line Sensor Use Cases

• Faster outage restoration
  • “Narrow down” the location of a fault
  • Reduce outage response time

• Provide more accurate current flow information to operators and engineers

• Provide more accurate current flow to engineers to support better planning of the distribution system
Missing Pieces

No existing systems that can utilize the best of all existing systems and still provide inexpensive instantaneous communication.
Currently In-Use Isolated Systems

GIS – Geographic Information System
  • Evolved over a long time period at PG&E
FLISR – Fault Location, Isolation and Service Restoration (FLISR)

• Distribution automation application that networks groups of switches on a feeder to vastly improve the reliability of utility delivered power by “localizing” outages.

OMS – Outage Management System

• Only tracks live issues, once resolved, they are gone. Row based database.
Current Isolated Systems (continued)

ILIS – Outage Tracking Tool

- Slow to update and cumbersome to follow.
- Historical outline of events after they have happened and have been resolved.
DMS – Data Management System
• Operators can see icons when calls come in and the power grid, but they don’t know where the outage is and often dispatch T-Men to 20-40 miles of power lines to check it out.
Line Sensors Are New & Must Integrate With Existing Processes
PG&E DTOC

• The DTOC housed the Line Sensor Pilot Operations Team
PG&E Decided to Create a Distribution Technology Ops Center (DTOC)

- New Department
- Defined Roles for participating engineers
Line faults were actively monitored and reported during the pilot project.
PG&E Line Sensor Pilot Project Timeline

- 2014
  - DTOC evaluated about a dozen Line Sensor products from various manufacturers
- 2015
  - DTOC chose 2 overhead and 1 underground vendor for the pilot deployment
  - Mid year, DTOC successfully deployed over 1,300 overhead line sensors on over 200 feeders with both cellular and Mesh technologies.
- 2016
  - DTOC deployed over 30 underground cellular locations in 2016, and over 30 rural locations to investigate secondary use cases
What were the Real Issues during the Pilot?

• Logistical issues of deploying and installing line sensors
• IT Integration – Each database has it’s own set of requirements
• Capture Data from the line sensors – Who will receive & monitor the data? Interpret data from field- Report the right data to the right party
Pilot uncovered who really cared about Line Sensors

1. Program Sponsor
2. Dispatcher
3. Field Crews
4. EOC Teams
Line Sensor Project Metrics - Outage Benefit Analysis Methodology

Create the Outage Report Card:
• ILIS Report and OIS Outage Report (Raw Data) for sustained outages.

Filter out events with no possible benefits:
• Planned / crew requested outages
• Transmission line / substation / source side outages
• Events with abnormal switching / FLISR
• Non-main line outages (fuses / transformers)
• No line sensors beyond a recloser or SCADA switch

Answer five questions regarding those outages with potential benefits:
• Did the line sensors behave properly?
• Was there a switching operation available?
• Were dispatch directives available?
• Was CFL (Calculated Fault Location) data available?
• Would the CFL data have provided additional dispatch directives?
The kickoff for line sensor hardware installation

Identify the site locations
  • Cellular coverage? Mesh?
  • Mesh is cheaper to operate

Coordinate with Vendors, create purchase order to receive inventory

Create the plan/schedule for delivery and installation
Circuit Map Change Sheet

- Once the sites are qualified and selected, a Circuit Map Change Sheet was approved by the engineer in order to install a device on the power line.

- This sheet gives the T-line man the authority to install the device and the location at which to be installed.

- There is information needed from the T-line man to be recorded that needs to go back to the operations team.
Inventory Master List

When a CMCS sheet is received, all of the data from the T-line man must be recorded to be able to produce statistics and to get the devices uploaded into their respective databases.
Enter device deployment data into Vendor Head Ends (Tollgrade)

When the CMCS comes back from the field, the data received needs to be entered into the vendor specific head end so that the until will begin to work and collect data.
Enter device deployment data into Vendor Head Ends (Sentient)

When the CMCS comes back from the field, the data received needs to be entered into the vendor specific head end so that the until will begin to work and collect data.
Inventory Record was captured in GIS

When a device is installed on the grid, the device information needs to be uploaded into the GIS database inventory record. The GIS will push the data into the DMS server to create the location info.
An IT specialist on the project team was responsible for planning Data Flow.
Remember this slide?

Line Sensor End-to-End Solution

Commissioning, asset management, Diagnostic Center investigations

Engineering Studies

Real time fault location and line switching

Smart meter and cellular communications

Head-End Systems

PI

DMS

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PI Historian served as the link to the Line Sensor devices and data

<table>
<thead>
<tr>
<th>AOR5</th>
<th>San Jose</th>
<th>EVERGRE</th>
<th>EVERGREEN-2103</th>
<th>Tollgrade</th>
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<th>LS100162_3</th>
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Loading Data as displayed via PI Data Link
Other examples of engineering data from Pi Historian

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PG&E selected 7 DNP3 points for common status reporting for all Line Sensors

- Data Point Name
- Loss Of Current
- High Current Status
- Permanent Fault
- Momentary Fault
- Line Disturbance
- Sag Fault
- Surge Fault
DNP Points were mapped into PI Historian (vendor specific)

- **Tollgrade**
  - Fault Current (a)
  - High Current (a)
  - High Current Status (b)
  - Line Disturbance (b)
  - Line Disturbance Current (a)
  - Loss Of Current (b)
  - Momentary Fault (b)
  - Momentary Fault Current (a)
  - Permanent Fault (b)
  - Power Factor (a)
  - RMS Current (a)
  - Sag Dips Exceeding Thresh (a)
  - Sag Fault (b)
  - Surge Dips Exceeding Thresh (a)
  - Surge Fault (b)

- **Sentient**
  - Current Direction (b)
  - Fault Alert (b)
  - Fault Threshold Current (a)
  - Loss of Communication (b)
  - Loss of Service Alert (b)
  - Loss of Voltage Alert (b)
  - RMS Current (a)

Note: fault classification logic in the DMS

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Provisioning Task List was Complex!

CMCS

Inventory Sensor Master List

Head End Entry

Line Sensors

DNP Index

Head Ends

Communication Server

Concentrator

PI Interface

PI Server

PI Connector

IT

DMS

Enterprise Integration

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Task List Status Tracking was also Complex
Final Product: Distribution Operators viewed Line Sensor status via DMS
Symbols in the DMS

• One line sensor symbol per location (3 sensors) displayed in the DMS
• Select “Line Sensor Display” option in the right click menu off a Line Sensor symbol to access reported data

- Normal
  - Orange = No Fault (default)

- Faulted
  - Blinking Cyan = Permanent Fault

• “NO COM” tag next to symbol when LS communications lost
DMS example showing multiple Line Sensors

Right click on a LS symbol and launch the Line Sensor Display to see its data.
Line Sensor Display after a Right-Click

Selecting a LS name will locate it in the DMS map and show Loading Data below.

LS data

Animated Symbols in DMS lead to faulted zone
Live DMS Display of LS Data

1. Single Line Diagram

2. Operational Data

3. Loading Data of selected LS

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Single Line Diagrams

- The Single Line Diagram (SLD) is used as a reference to indicate the locations of LS on the feeder in relationship to the protective devices.
- LS correlate with rows in the table below the diagram.
- LS are shown as gray diamonds (not animated) in the SLD.
- Substation and protective devices are shown as red symbols.
### Operational Data Table

- **Per LS Location:**
  - Feeder – Name of feeder where Line Sensor is installed
  - Line Sensor – Name of LS location (Operation Name)

- **Per LS Device:**
  - Phase ID – Label associated with a LS device at a given location on the feeder. Line sensors are installed in triplets, e.g., LS100254_1 on “A”, LS100254_2 on “B”, LS100254_3 on “C”.
  - Last Loading Data – Latest of periodically collected RMS Current values (e.g., @ 15 min) from associated LS
  - Status – Communication and Power status of LS (details follow)
  - Fault – details of faults reported by the LS (details follow)

#### Table

<table>
<thead>
<tr>
<th>Feeder</th>
<th>Line Sensor</th>
<th>Phase ID</th>
<th>Last Loading Data</th>
<th>Status</th>
<th>Permanent Fault</th>
<th>Momentary Fault</th>
</tr>
</thead>
<tbody>
<tr>
<td>LOS GATOS-11B</td>
<td>LS100254</td>
<td>1</td>
<td>03-15-2018 13:50:00</td>
<td>ON</td>
<td>2301A</td>
<td>2301A</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2</td>
<td>03-15-2018 13:50:00</td>
<td>ON</td>
<td>2301A</td>
<td>2301A</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3</td>
<td>03-15-2018 13:50:00</td>
<td>ON</td>
<td>2301A</td>
<td>2301A</td>
</tr>
</tbody>
</table>

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Status

- Com – communications status of LS device
  - Blank = Communicating OK
  - “NO COM” = LS has not communicated for 75 minutes or longer. All data cells will show as gray text
  - “NOT COMMISIONED” = LS is present in the DMS but PI data has not yet been commissioned. This is a temporary state for newly installed LS while commissioning is in progress. All data cells will be blank

- Power
  - ON = Associated LS is energized
  - OFF = not energized
Fault Data

Fault

• Permanent Fault
  • Fault = Color code indicating the presence of a sustained fault reported by LS device (Orange = No Fault; Blinking Cyan = Fault; Gray = Status unknown (when device not communication))
  • Fault Current = Value and Timestamp of latest reported permanent fault

• Momentary Fault
  • Fault Current = Value and Timestamp of latest reported permanent fault

Notice: Fault Current values older than 24 hours show as gray text; recent values as black
Loading Data

- RMS Current historic data trend of selected LS (indicated by red rectangular frame) is shown below the table
- Mouse-over the graph for RMS values at a specific time
- Select graph section to zoom in

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Summary of Data Products from Project

• 10 min Report Cards
  • Operators
  • Engineers
  • T-Men

• Morning Health Check to make sure devices are online

• Reporting Tools for management
  • App showing various metric –periodic performance report schedule based
    • Determining “Up Time”

• Special Analysis
  • Warriors game
Line Sensors on Warriors Stadium Feeders

• 6 locations established on Oakland J 1110 and 1103 feeders

• Load values look normal and consistent.
• No events from Line Sensor data.
• Investigating out of phase on one sensor.
EGT Diagnostic Center
Oakland Arena - Line Sensor Monitoring
Oakland J1110

- 7 locations on active power feeds to the Stadium monitoring the Warriors game
- Load values look normal and consistent (peaking at game times)
- No suspect events from Line Sensor data
### Sensor Details

#### Sensor Status

<table>
<thead>
<tr>
<th>Carrier Network Type</th>
<th>Name</th>
<th>MAC Address</th>
<th>Cell Id/ESN or IMEI</th>
<th>Power State</th>
<th>Last Current</th>
<th>Last Voltage</th>
<th>Measurement Time</th>
<th>Cell Data Cell State</th>
<th>Cell Connection Type</th>
<th>Cell RSSI</th>
<th>Cell ECI0</th>
<th>Cell Roaming</th>
</tr>
</thead>
<tbody>
<tr>
<td>CN_1</td>
<td>LS100109_2</td>
<td>00001A</td>
<td>60F66E9B</td>
<td>on</td>
<td>3</td>
<td></td>
<td>2016-09-01 12:30:00</td>
<td>disconnected</td>
<td>1XRTT</td>
<td>-70</td>
<td>-6</td>
<td>yes</td>
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<tr>
<td>CN_1</td>
<td>LS100109_3</td>
<td>00002F</td>
<td>60E3FFD5</td>
<td>on</td>
<td>7</td>
<td></td>
<td>2016-09-01 15:00:00</td>
<td>disconnected</td>
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<td>-73</td>
<td>-5</td>
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<tr>
<td>CN_1</td>
<td>LS100109_1</td>
<td>00007D</td>
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<td></td>
<td>2016-09-01 15:30:00</td>
<td>disconnected</td>
<td>1XRTT</td>
<td>-70</td>
<td>-7</td>
<td>yes</td>
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### Delete

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<tr>
<th>Carrier Network Type</th>
<th>Name</th>
<th>MAC Address</th>
<th>Cell Id/ESN or IMEI</th>
<th>Region</th>
<th>Substation</th>
<th>Circuit</th>
<th>Location Name</th>
<th>Phase</th>
<th>Phase Reference Location</th>
<th>Phase Reference Distance (miles)</th>
<th>Serial Number</th>
<th>Version</th>
<th>Type</th>
<th>Latitude</th>
<th>Longitude</th>
<th>Cell SW Version</th>
<th>PRL Version</th>
<th>Phone</th>
</tr>
</thead>
<tbody>
<tr>
<td>CN_1</td>
<td>LS100109_2</td>
<td>00001A</td>
<td>60F66E9B</td>
<td>PGE</td>
<td>PILOT</td>
<td>PERRY</td>
<td>LS100109</td>
<td>C</td>
<td></td>
<td>6091445487</td>
<td>6.1.5</td>
<td>0.943434</td>
<td>35.557323</td>
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<td>d3111301</td>
<td>53004</td>
<td>41559354340</td>
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<td>00002F</td>
<td>60E3FFD5</td>
<td>PGE</td>
<td>PILOT</td>
<td>PERRY</td>
<td>LS100109</td>
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<td>-121.081737</td>
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<td>PERRY</td>
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<td>d3111301</td>
<td>53004</td>
<td>4159084046</td>
<td></td>
</tr>
</tbody>
</table>
Sample of Wave Form from Head End

Waveform File From Sensor (LS100069_2) : 2016-05-05 07:35:37 - 000143-C.dat

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Value added use cases for Engineers:

- Failing equipment
  - Cap banks, transformers, or unreliable metering

- Balance the load between the phases
  - Real time current readings

Low cost substitute to SCADA
- Distributed Generation
Characteristic Waveforms

- Cap Bank operation
- Cable joint fault/Splice
- Fuse Operation
- Load Switching

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Calculating Fault Location

Stan Thompson
First Let’s Define CFL: The Broad Definition

Calculated Fault Location is an attempt to determine the location of a fault within several pole spans

**Traditional CFL (TCFL):**
- Calculation of fault location based solely on data collected at substation using Voltage/Current readings.
- An example of how to do this uses CYME

**Comprehensive CFL (CCFL):**
- Calculation of fault location is based on:
  - Voltage and current measurements made at the substation
  - Current measurement made on the primary of the distribution line (Line Sensors)
  - Voltage measurements made on transformer secondaries along the distribution line. (Voltage Sag Monitors)
Traditional Calculated Fault Location (TCFL)

Our Experience to Date

TCFL calculates the number of wire-miles to the fault location using CYME calculation voltage and current data collected at the substation

**Strengths:**
- Uses data already available from line reclosers and substation relays and alternative to large line sensor rollout
- Reasonable job of calculating the distance

**Shortcomings:**
- Identifies multiple potential locations – numerous locations do not lead to meaningful benefit
- Errors are often introduced due to imprecise modeling assumptions
### Original Visualization of CYME Analysis

**Run CFL**

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feeder Name</td>
<td>Feeder Number</td>
<td>Date/Time</td>
<td>Fault Current, Amp</td>
<td>Fault Type (LLL, LLG, LL, LG)</td>
<td></td>
</tr>
<tr>
<td>KemOh1108</td>
<td>2527211608</td>
<td>5/31/2016 11:41:10</td>
<td>552</td>
<td>LL</td>
<td></td>
</tr>
</tbody>
</table>

**Create fault-zone csv**

Enter path of the working directory:

C:\Users\SSTF\Documents\CYME\CFL

Enter path of [feedername]-NodeFaultDuties.xlsx file:

C:\Users\SSTF\Documents\CYME\CFL\NodeFaultDuties

Enter path of [feedername].LatLong.xlsx file:

C:\Users\SSTF\Documents\CYME\CFL\NodeFaultDuties

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New Visualization of CYME Analysis
Results: Bracketing of a Fault Location Using Line Sensors

Line Sensors bracket a fault location. Line Sensors provide loading data for switching and capacity planning decisions.

**Strengths:**
- Easy to install & to understand fault location information
- Reasonable job of calculating the distance
- Potentially provides additional data for CCFL model
- Provides data for switching and capacity planning

**Shortcomings:**
- Will not work with low current
- 10x the cost of non-communicating faulted circuit indicators (FCI)

In this example the Line Sensors bracket the fault to the top branch.

<table>
<thead>
<tr>
<th>Sensor Location</th>
<th>Date/Time</th>
<th>Sensor Name</th>
<th>Phase</th>
<th>RMS Current</th>
</tr>
</thead>
<tbody>
<tr>
<td>40</td>
<td>5/18/2016 17:12</td>
<td>LS100146_1</td>
<td>A</td>
<td>1504</td>
</tr>
<tr>
<td>40</td>
<td>5/18/2016 17:13</td>
<td>LS100146_3</td>
<td>B</td>
<td>276</td>
</tr>
<tr>
<td>40</td>
<td>5/18/2016 17:12</td>
<td>LS100146_2</td>
<td>C</td>
<td>1447</td>
</tr>
</tbody>
</table>

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Bracketing of a Fault Location Using Line Sensors

Line Sensors bracket a fault location. Line Sensors provide loading data for switching and capacity planning decisions.

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<td>C</td>
<td>1447</td>
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</tbody>
</table>

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The “Calculation Gap” that led to use of Voltage Sag Monitors

Shortcomings Necessitate Moving from TCFL to CCFL

TCFL Shortcomings
• Estimates a fault distance from substation but doesn't determine which branch the fault is on (and there can be many)
• Modeling assumptions are not precise and can lead to errors in prediction
• Lack of current measuring devices?

LS Shortcomings
• Line Sensors determine whether the fault/current passed their particular location however this may not localize the actual fault location.
• They don’t work far down the line due to lack of current,
• Cannot install if wire is too small, more expensive installation
• Line Sensors precisely measure the current; but cannot measure the voltage

Filling the Gap with VSMs:
1. Reduce the number of potential locations from TCFL
2. Improve the accuracy of the modeled line impedances in TCFL
3. Provide sensor data in locations where LS is not practical
Voltage Sag Monitors Monitors Help Fill The Gap

• VSMs precisely measure the voltage that line sensors cannot
• The findings thus far indicate that voltage sag monitors have a place & there is much more potential for leveraging data
Our Experience to Date with VSM

- Voltage Sag Monitors that measure and report voltage drop during fault events
  - Additional VSM sensor complements aforementioned
  - Supplements the calculation for fault location.

The measured RMS voltage during the fault event, when combined with the VSM installation location along the distribution line, can be used to predict the fault location.
Using Comprehensive Data to Pinpoint CCFL

Fault Location Using:
1. Substation CFL Alone
2. TCFL plus Line Sensors
3. TCFL, LS, plus Voltage Sag

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VSM Conclusions: More “Bang for the Buck”

• VSMs can be deployed all the way to the end of the feeder
• VSMs make CFL accurate
• VSMs provide power quality and voltage data important for DG
• Augmentation of Traditional CFL with VSM converts a “nice-to-know” application to a mission-critical benefit for operators
• PGE found value using the voltage sag monitors

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VSM Relationship to Smart Meters

• We installed 5M smart meters.
• Can they fulfill the function of a VSM? Yes... In principle, but there is no “quick fix.” Time, money and research will be necessary.
• SM are mission critical – billing – would require hardware implications & this would be a many year process.

VSMs are immediately applicable
Both Traditional CFL & Line Sensors had shortcomings that can be mitigated with use of VSMs

• VSMs are a cost attractive solution to solving the CCFL puzzle; (of our solutions this is a lower cost approach.

• VSM function may be included in a SmartMeter function in the future but that is a long way off.

• VSMs provide a solution for near term CCFL efforts.

• VSM rollout will pay for itself quickly & will fill the need during the years it will take to develop SmartMeter implementation
Conclusions

• What worked for PG&E is a combination of line sensors, CFL, voltage monitors and existing infrastructure, resulting in the dissemination of crucial information within 10 minutes
BREAK
(15 minutes)
DP&L Overview
Serving the Region for Over 100 Years

• 6,000 square miles in 24 counties in Ohio
• 1,400 employees
  • Generation
  • Customer Service Operations
  • Field Operations
• DP&L is an AES company
• Indianapolis Power & Light is sister AES company

©TAV Networks, Inc. 2017
AES, A Fortune 200 Global Energy Company

- 17 countries across 4 continents
- 35 gigawatts (GW) of generating capacity
- 7 utility companies including 8 GW of generating capacity
- $15 billion in annual revenues
- A global workforce of approximately 21,000 people
Asset Management Function

• Allow assets to be monitored real-time
• Track equipment operations to decide maintenance cycles
• Power quality data can be captured and analyzed to predict future equipment failure through data trending
• Sensor data can feed Distribution Management Systems for real-time modeling of the distribution system. Allows for optimization of the utility assets
• Sensors can provide many data points for asset systems to analyze
• Data is key to better analytics and this leads to better asset management
Line Sensors - an alternative to expensive distribution assets

- Hydraulic Recloser and Sensor vs Electronic Recloser
- Circuit Monitoring at Substation vs RTU and Digital Relays
- Planning Tools – Sensors Monitoring Load vs Load Logger Technology
- Monitor Capacitor Ground for current flow. Signals a blown fuse on the three phase bank.
- Monitor circuit balance at points along the circuit.
- Potential to use for vegetation growth. Based on small interruption or small current fluctuations.
- Fault detection and reporting on the distribution system
Sensor as Circuit Monitor at Substations

• Substations that do not have an RTU installed today.
• Sensors will be deployed on each circuit leaving the substation.
• Circuit monitoring can be achieved at much reduced cost. Sensors are Approximately $3500 per circuit installed.
• RTU with communications is approximately $50k - $75k before digital relays are installed.
• Sensor allows circuit loading, alert when circuit has operated, aggregate of circuit loads provides transformer loading.
• Sensors are monitoring only, where as RTU provides control at the substation.
Sensors as Planning Tools

• Sensors = $1000 each – Load Loggers are $1600 each.
• Sensors provide data near real-time load data to the engineers.
• Sensors don’t need batteries.
• Load Loggers need to be installed for a period of time and then removed to retrieve the data.
• Load logger needs software to download data.
• Sensor supplies data to utility system of choice.
Hydraulic Recloser and Sensor

• Cost Savings of $2000 per installation
  • (Hydraulic Recloser + Sensor = $2500 + $1000 = $3500
  • Electronic Recloser = $5500)

• Sensor will alert the operations center when it has operated and went to lockout.

• Sensor will allow for tracking number of operations on the recloser.

• Sensor will provide real-time amperage data to understand loading on the recloser.
Program at DP&L

• Install a line sensor at four locations with hydraulic reclosers.
• Unit is installed on the load side of the recloser.
• Installation is on one rural circuit.
Circuit One-line Diagram
Data from the Sensor for Recloser Monitoring and Maintenance

• Simulate counter with operations of sensor.
• Loading on the recloser
• Open/close timing of the operations
• Total interrupt energy on the unit
Sensor Data Chart on 3 single phase reclosers
Power Quality Monitoring

Jeff Teuscher
Problem

• Limestone Mining Operation employees were receiving shocks when they were setting charges into the wall.
• Customer contacted the utility for help on finding the problem as the customer was concerned for employee safety.
• Two 13.2 Grounded Y primary metered services to the mine.
• Both services are close to the utility substation
• Customer runs four wire overhead primary to multiple MV-LV transformers.
• Grounding practices were MSHA non-coal (primary neutral bonded to secondary neutral and local earth electrode)
• Customer thought they did not use the neutral but was unsure of the actual use of the neutral for transformers and other
• Customer was unwilling to take any outages to separate phases and neutral from utility for standard NEV (neutral to earth voltage)test.
• Detailed inspection of customer facilities was overly difficult and expensive
Problem Area in Mine
Circuit Map to Limestone Mine

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Diagnostics/Findings

• Critical to know details of neutral current in neutral wire without requiring an outage for the customer or an extensive inspection
  • Total current and correlation to NEV
  • Amount of current due to customer load
  • Amount of current due to substation neutral return current

• PQ meter at metering point
  • Measured neutral current demanded by customer
  • Measured frequency spectrum of demanded neutral current
  • Measured NEV.

• Line sensor
  • Measured the total neutral current (customer demand and substation return)
  • Measured frequency spectrum of total current – especially important third harmonic.
  • Trend data went to PI data historian for correlation with PQ and revenue meter

• Neutral current and NEV at the substation was determined to be almost all 3rd harmonic.
  • This offered an opportunity to further identify current contributions
  • Third harmonic would be substation
  • Fundamental would mostly be customer
Led to finding capacitor with blown fuse

High neutral current cleared after tree outage
Conclusion

• Neutral current monitors confirmed NEV was caused locally and not by utility
  • Neutral currents in revenue meter and line sensor predominantly fundamental.
  • Neutral current magnitude in revenue meters closely matched the line sensor current measurement.
  • NEV correlated with current recorded in PI by line sensor.

• No outage or extensive inspection was needed

• Neutral current monitors confirmed faulty equipment on one service and blown capacitor fuse on the other
  • Faulty equipment had highly fluctuating neutral current and equipment failed while the line sensor was in service. Line sensor confirmed the current reduction after repairs.
  • Line sensor and PQ meter on other service indicated neutral current may be due to capacitor. Capacitor was easily located and did have blown fuse with other phases connected to neutral.

• Stray voltage was from the customer high neutral currents
  • Lighting carried NEV into the mine through the equipment grounding conductor that was bonded to the primary neutral as per MSHA and NEC requirements.
  • High moisture content and strata conductivity “energized” large areas of the mine wall.

• Customer now understands importance of very low primary neutral current and has established a monitoring program.
Other PQ Sensor Charts

Potential of an intermittent fault – Could represent a failing line arrestor

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Sensor PQ – Harmonic Distortion

Line fault and Harmonic distortion of the current wave shape.
Vegetation Management
Joe Tavormina
Grid Maintenance Today

- Mostly reactive (following outage)
- Aging assets
- Declining number of personnel
- Outages are difficult to locate
- Root cause of outage often not resolved
Outages may be avoided by locating and characterizing non-persistent faults

- Non-oxidized conductor indicates a recent fault probably caused by vegetation
Vegetation issues lead to financial liabilities

PG&E, Contractors To Pay $51M To End Calif. Wildfire Suits
By Kurt Orzech

Law360, Los Angeles (June 6, 2013, 8:31 PM EDT) -- Pacific Gas and Electric Co. and its contractors have agreed to pay $50.5 million to settle litigation over two California wildfires that burned more than 18,000 acres of national forest and cost $13.5 million to suppress, the U.S. Department of Justice announced Thursday.

The U.S. alleges that the defendants' neglect caused the Power Fire and the Whiskey Fire, which occurred in October 2004 and June 2008, respectively. The first fire occurred in Eldorado National Forest in Amador County in a remote location near the Salt Springs...

PG&E to pay out at least $350 million in Butte Fire claims
By Dana M. Nichols dana@calaverasenterprise.com
Nov 28, 2016

Almost 100 of the 1,856 individuals who are suing Pacific Gas and Electric Co. over losses caused by the Butte Fire have agreed to settlements with the utility company and its contractor Trees Inc., according to a court document.

Attorneys for the plaintiffs and the defendants said in a joint case management statement filed Nov. 18 that 53 households including 98 plaintiffs and a total of 123 individuals (some of whom were not named plaintiffs) have settled their claims.

The Butte Fire that began Sept. 9, 2015, burned more than 70,000 acres and destroyed more than 500 Calaveras County homes as well as hundreds of barns, sheds and well houses. The California Department of Forestry and Fire Protection concluded in a report issued in April that a tree trimming crew hired by PG&E failed to remove a gray pine that later fell, contacted a power line, and started the fire.
Assessment of non-persistent faults from Hydro-Quebec

- Non-persistent faults represent up to 70% of faults in distribution circuits
- Typically caused by vegetation contact or defective equipment
- Often deteriorate into outages
- Often responsible for many repetitive unsolved outages

Credit: Bryan Texas Utilities Web Site
Voltage Sag Measurements can be used to Locate Fault and Identify Cause

- **Hydro-Quebec MILES project**
  - Located and repaired loose conductor that heated and expanded under high current load
  - Located non-persistent, repetitive fault due to vegetation in presence of wind gusts (no rain)

- **PG&E Line Sensor Pilot project**
  - Addressing liabilities related to forest fires in the foothills of Eastern California

Reference: Marion Tremblay, Hydro-Québec IREQ, Distributech February 2016

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Analysis of non-persistent faults requires analytics beyond current practice

• Asset associations and location
• Event records
• Background analysis
• Notifications manager
• e.g. SensorConnect by TAV Networks, Inc.
Potential Benefits

• Reduction of outage frequency (up to ~50%)
• Reduction in SAIDI Index (up to ~60%)
• Reduction in Outages with Unknown Cause (up to ~90%)
• Avoidance of unnecessary investment (Millions of $$$)
• Mitigation of liability for wildfires

Credit: Asplundh Web Site
Lessons Learned from Line Sensor Deployment Projects

Jared Hafer
Planning a Line Sensor Project – Scope

- What Business Benefits are desired from the Line Sensor Deployment?
  - Needs
  - Wants
  - Expectations
- Anticipation of scope “creep”?  
- Plan to prevent this “creep”? 

Proposed pilot deployment areas 1 and 2A

<table>
<thead>
<tr>
<th>Area</th>
<th>Expected # of locations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fresno</td>
<td>60</td>
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<tr>
<td>Kern</td>
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<td>Stockton</td>
<td>120</td>
</tr>
<tr>
<td>SLO</td>
<td>120</td>
</tr>
</tbody>
</table>

*Location is a triplet of line sensors*

Planning Engineers are completing the final list of feeder candidates with proposed line sensor installation locations.
Articulating Anticipated Business Benefits

• Fault Detection, Location, and Rapid Restoration
  • Decrease Windshield Time for Troublemens by knowing a precise fault location
  • Decreased outage durations for customers due to faster responses

• Power Quality Monitoring
  • Distribution planning
  • Troubleshooting

• Asset Management
  • Cost savings in Operations and Maintenance
  • Substation automation

• Other benefits to utilities from Line Sensors?
Planning a Line Sensor Project – Deployment

Identify deployment locations
- Outside substation
- After first recloser
- Known troubled areas
- No SCADA areas
- For Reliability or Planning?

Qualify locations
- Current on feeder
- Radio network coverage
- Local conditions (i.e. inside vault?)
- Field Inspection Confirmation

Installation orders / maps
- Lat/long
- Protective device ID
- Conductor size (2/4/6 AL/CU may need a line guard)
- Hot stick vs rubber glove install
- Access / property issues

Installation training / documentation
- Process for determining RF coverage, line current, phase ID, and location
- Deployment data management
Deployment Schedule Issues/Risks

• Significant schedule risks during deployment
  • **Weather**- One would be shocked to learn how many of our clients forget to consider winter snow or extreme summer heat when putting together their deployment schedules.
  • **Uninformed Customers**- Uninformed customers will ask their neighbors or the internet what the new device being hung on their power line is. Be sure to let customers know what you are doing and why, so they are properly informed.
  • **Legal Issues**- Can a device be installed where it is desired? Is permission needed or are right of way agreements required in advance of installations?
  • **Unreliable Vendors**- What happens when an equipment vendor misses a delivery date, or equipment fails in the field?

• How can known project risks be mitigated?
Planning a Line Sensor Project – QA

• What is the deployment success criteria?
• How will success metrics be monitored / tracked?
• What processes will be put into place to remediate devices that are not functioning properly?

Deployment locations were screened for communications viability. The one on the right was deemed too risky.
Planning a Line Sensor Project - Resources

• What existing resources are available for assignment to project?
• What additional resources need to be engaged for the project?
• How will human resources be managed for the project?
Planning a Line Sensor Project – IT Integration

• Legacy information systems
  • GIS
  • Data Historian
  • Outage Management
  • Distribution Management
  • SCADA

• Data repository for Line Sensors

• Deployment data management
  • Paper-based?
  • Electronic?

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Planning a Line Sensor Project – Ops Integration

- Legacy Operational Processes
- New Decision Processes
- Primary Users
  - Existing GUls
  - Constraints
- Executive Users
  - Metrics
  - Periodic Reporting
Lesson Learned – IT Development

• Line Sensor deployment drives:
  • Acceleration of organizational decisions regarding “Advanced DMS”
  • Expose network security concerns
  • Highlight the significant cost associated with IT assets and development

• Response:
  • Postponement of IT Integration during pilot project
  • Adoption of hosted network management and data collection
Lesson Learned – Deployment Planning

• Line Sensor deployment success requires confirmation of:
  • RF Coverage
  • Line Current
  • Phase Identification
  • Location
  • Local Conditions

• Response:
  • Field Engineering is required
  • Appropriate field engineering resources are required
  • Appropriate field engineering tools are required
Lesson Learned – Deployment Data

• Line Sensor adoption requires:
  • Integration with legacy information systems
  • Retooling of legacy operational decision processes

• Response:
  • Paper-based processes are slow and time-consuming
  • Installation data collected on paper gets lost
  • Deployment project plan needs special consideration of this problem
  • Data management tools that address this problem are needed
Lesson Learned – Field Engineering Tools

• Field Engineering Tools conserve significant time and cost during a deployment project
  • Location Qualification
  • Deployment Data Collection & Management
Q&A
(15 minutes)
Index of Abbreviations

ADMS – Advanced DMS
AMI – Automated Metering Infrastructure
CPUC – California Public Utility Commission
DA – Distribution Automation
DMS – Distribution Management System
DNP3 – A Common Serial Communication Protocol
DP&L – Dayton Power & Light
NERC-CIP – DoE Regulating Entity

NLOS – Non Line Of Sight
ODN – Operational Data Network
OMS – Outage Management System
PG&E – Pacific Gas & Electric Company
RTU – Remote Terminal Unit (part of SCADA system)
SCADA – Supervisory Control and Data Acquisition
UDN – Unsecured Data Network
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