Remote Data Monitoring and Data Analysis for Substations—A Case Study in Implementation

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REMOTE DATA MONITORING AND DATA ANALYSIS FOR SUBSTATIONS—A CASE STUDY IN IMPLEMENTATION

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ABSTRACT

Today's intelligent electronic devices (IEDs) and robust communications processors contain large amounts of valuable substation data that have been available for years but largely overlooked. Initial integration efforts by most vendors focused solely on providing data access and control of Supervisory Control and Data Acquisition (SCADA) type data from the IEDs to replace separate SCADA hardware such as RTUs. Following the RTU replacement method led many vendors to use SCADA protocols to retrieve these data for use in supervisory operation. Choosing to use SCADA protocols, such as Modbus®, DNP, and UCA led to the problem that data unsupported by these protocols were trapped in the IED and unavailable. Stranded data include historical performance information, equipment monitoring data, device diagnostic data, automation data, as well as settings and configuration information. A few innovative utilities have been managing these data through remote monitoring and making them available for use by all divisions of the company. Today's data tools and communications methods allow every utility to take advantage of these data to truly manage their power systems. This paper is a case study of remote data monitoring and data analysis design and techniques. This remote monitoring technology greatly reduces power system operation and maintenance (O&M) costs while providing valuable information to system planning and operating departments.

INTRODUCTION

In the late 1990s, a large electrical utility in the southern United States began developing an automation strategy for transmission substations. Historically, they had utilized separate equipment for SCADA and protective relaying functions in the substation. This legacy equipment consisted of electromechanical relays and telemetry SCADA systems; combining protection and SCADA functionality was not possible. Beneficial functionality, such as sequence-of-events (SOE), digital fault recording (DFR), breaker condition monitoring (BCM), and annunciation would require installation of separate equipment. Since additional equipment from multiple vendors does not typically utilize a common communications pathway, this would have resulted in higher installation and maintenance costs as well as low reliability.

The ability to retrieve operating information to assist in maintenance and engineering analysis is greatly hampered by this system architecture. Furthermore, most of the SCADA and protective relaying equipment was approaching an age where end-of-life issues needed to be considered. The utility formed a team to develop and implement an automation strategy to address these obsolete terminals.

This paper is a case study of the data architecture and data management strategy adopted by this utility in 13 of their substations. This utility continues to design and build their substations using the microprocessor relay to fully integrate all protection, control, and monitoring functions required from an electrical terminal perspective.

SYSTEM ARCHITECTURE

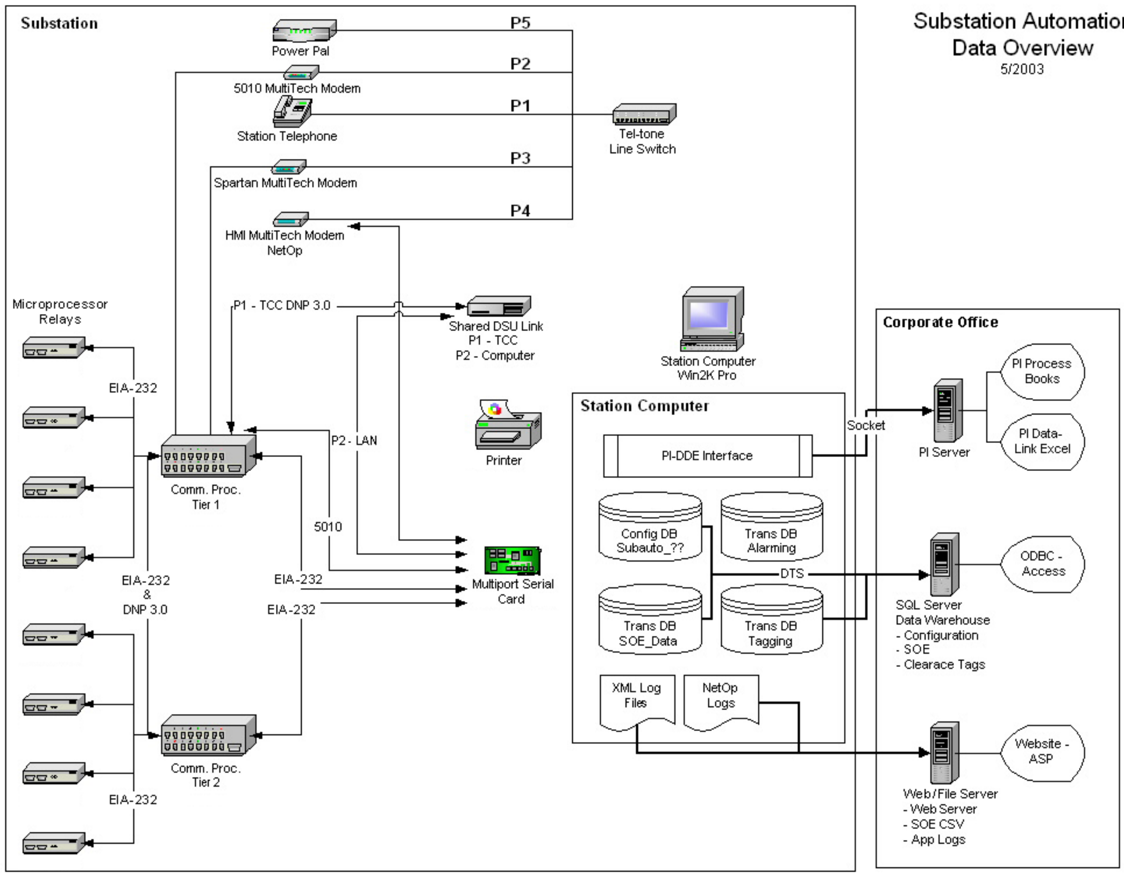


Figure 1 Substation Communications Hierarchy Overview

Figure 1 provides an overview of the communications hierarchy used at each substation. All protective relays and associated communications equipment connect to the communications processors via EIA-232 connections. The communications processors in turn connect directly to the substation computer. A serial card enables multiple EIA-232 connections to the substation computer. Two-tiered communications processors allow access to the relays from the substation computer using the manufacturer's software. All devices capable of accepting an IRIG-B time-sync signal interface to a GPS time-sync clock through the communications processors. Multiple servers reside at the corporate location; these include the OSIsoft PI server, Microsoft® SQL server, and a dedicated Web/File server. The substation computer is LAN-connected through a T1 line or a multiplexed shared line that provides data transfer to the servers. DNP 3.0 protocol over a dedicated digital leased line provides SCADA. This link interfaces directly over a multi-drop EIA-485 network to the communications processors. NetOp remote software over the LAN connection provides a backup method of control. This also provides engineering access to the substation computer. Engineering access is available through a secure phone switch and modem. The communications processors perform backup alarm notification by dialing a central computer anytime the main SCADA link is inoperable.

DATA FLOW

Microprocessor relays collect substation analog and status data over a serial connection. The communications processor polls or solicits data from the relays every second; SOE data travel up in an unsolicited fashion as they occur. The communications processor stores the polled data in multiple local apparatus-specific and system-wide databases, internal to the communications processor. These databases are exported to the computer on a one-second interval using a fast messaging protocol. Figure 2 shows the substation connection that makes all substation data available to the corporate servers.

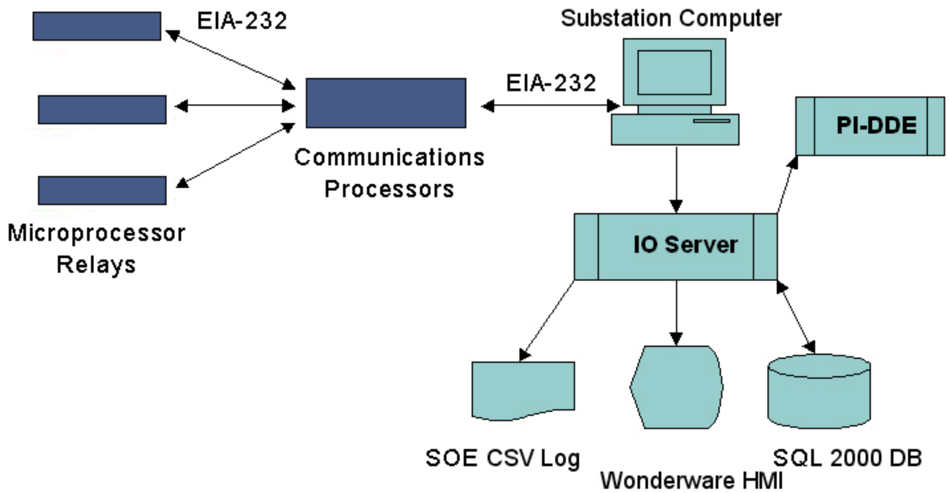


Figure 2 All Data Are Available to the Corporate Servers

Huge amounts of data are available from the substation IEDs. Thought must be given to how these data will be used and to which system the data will be made available. The team designed this system by identifying all data required by the utility's multiple divisions. The data were stored in the communications processor and then filtered, using an innovative method of data concentration, to limit the data transferred. Table 1 illustrates the number of data points managed at the substations and used by software applications and databases. It does not represent the total number of points available from the IEDs; these easily number five times the amount shown. Rather, it shows the result of data filtering to identify and transfer only the required data. Future data needs are easily supported by adding or removing data within the communications processors.

Table 1 Data Point Count for Each Substation

Substation	Wonderware® HMI	OSIsoft PI Server	Energy Management System (EMS)	Backup Alarming
1	776	358	272	121
2	775	365	268	105
3	776	357	257	113
4	1940	869	581	300
5	4500	1714	1432	621

Substation	Wonderware® HMI	OSIsoft PI Server	Energy Management System (EMS)	Backup Alarming
6	790	382	266	118
7	857	421	295	122
8	898	408	307	141
9	823	399	294	132
10	727	353	253	110
11	1408	662	466	215
12	4514	1714	1432	621
13	1037	505	333	155

Using a substation apparatus point of view, rather than the anonymous SCADA mentality, it is easy to see what additional data from the IEDs are useful. The following sections contain tables listing major substation apparatus data collected from the IEDs.

TRANSFORMER MONITORING

Table 2 Substation Apparatus Data Collection by IEDs

Traditional Data Points Available	Additional IED Data Points Available
Voltage	Fault Magnitude
Current	Demand Top Oil Temp. & Time
MW	Demand Winding Temp. & Time
Mvars	Load at Peak Demand Temp. & Time
Top Oil Temperature	MWh and MVarh Energy (In-Out)
Winding Temperature	Fans cycle
Oil Flow	Fan status (Run)
	Targets
	79, 51R-N, 62B, & 87B-T Blocks
	Setting Group Status
	Equipment Tagging
	Power Quality Measurements
	Transformer Loss-of-Life

The substation transformers represent the most expensive substation asset. Additional transformer monitoring information provided by the protection IEDs helps operators make informed decisions.

Energy Transfer Monitoring

Take the example of energy transfer. By calculating transformer loss-of-life and comparing this loss-of-life of the asset to the additional revenue value from an energy sale, a business case can easily be made if violating the utility's operating thermal rating of the transformer makes sense. Since real-time monitoring of this loss-of-life calculation is being stored into a database, a historical record of this loss is being maintained, trended, and factored into future maintenance and asset replacement programs.

Cooling Fan Monitoring

Cooling fan monitoring is an often-overlooked item of transformer maintenance. In the utility's cooler climates, the cooling fans did not operate for months at a time. This caused the oil lubricant in the fan bearings to become unevenly distributed. Failures were also caused by birds building nests in the fans. Monitoring fan operations and daily cycling the fans reduced fan failures and avoided transformer cooling loss. Figure 3 demonstrates fan monitoring.

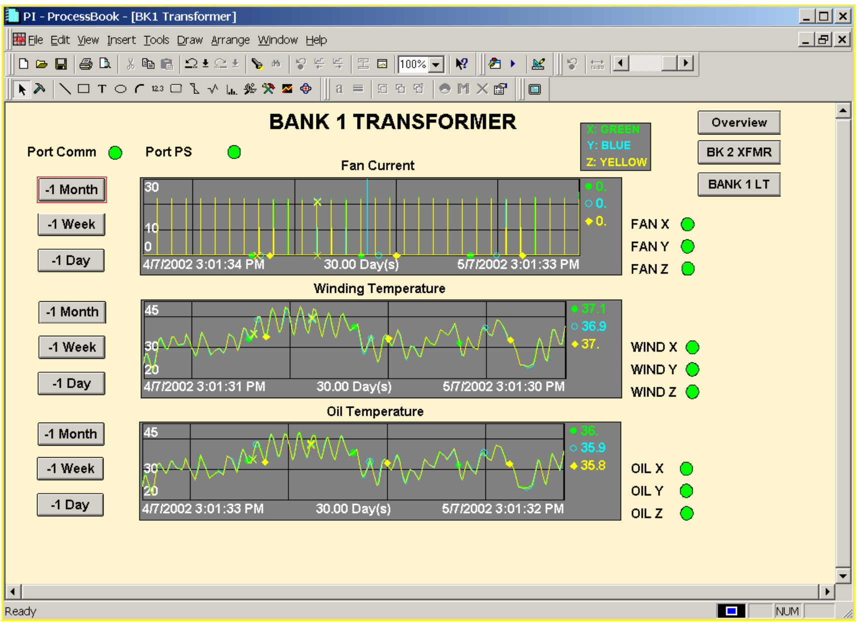


Figure 3 Monitoring Fan Operations Reduces Fan Failures

Transformer Temperature Monitoring

Monitoring and recording the transformer temperature can trigger a number of preventative maintenance measures. Limits can be placed on transformer temperatures to trigger "warnings" that can prevent catastrophes such as oil spills and supply a means to detect cooling system problems. Most utilities now rely on station inspections to trigger this maintenance, but observation alone does not verify the integrity of a transformer cooling system. In addition to station inspections, thermal monitoring methods can be added that allow verification of rating algorithms and rating violations; this monitoring greatly assists with planning for "unexpected" problems before they occur and placement of additional transformer cooling where needed. Visual inspection and peak demand reading does not allow concise determination of bank loading and experienced rating violations.

One example of this was illustrated when, after an oil spill, only "test loadings" and peak bank temperature values were in the utility's databases. The temperature readings suggested a rating violation, but the bank loadings during this time could not be verified. On the other hand, real-time monitoring of these values provides the needed correlation to perform verification.

Phase Current Monitoring

Another example made use of phase currents on transformers. Recording and tracking the individual phase currents allows system planning to be notified about load imbalance problems. The utility had a bank of three single-phase transformers that was operating below ratings. One of the three transformers was carrying significantly more load than the other two. This load imbalance created a rating violation on the overloaded transformer, but not on the other two transformers. The overloaded transformer created an oil spill that could have been prevented by using appropriate data monitoring, collection, and alarming.

BREAKER MONITORING

Table 3 Tracking Breaker Wear Indicators Reduces Maintenance Budgets

Traditional Data Points Available	Additional IED Data Points Available
Breaker Position	Fault Location & Magnitude
Reclosure Status	Gas Temperature
Voltage	Low Gas Pressure
Current	Low Air
MW	Air Compressor Run Time
Mvars	Interrupt Current by phase
	Operational Counters
	Targets
	51G & 62B Blocks
	86B Lockout
	Equipment Tagging
	Reclosing Type (Sync., HLDB, DLHB)
	Breaker Timing
	Breaker Condition Wear Indicator

Breaker wear indicators can now be tracked in a database and automatic triggers applied for maintenance. Implementation of a breaker wear indicator based on It or I^2t is much more accurate than the method of counting fault current interruptions. By tracking the actual wear and triggering maintenance on this indicator, the utility reduced the number of internal breaker inspections required since it schedules internal inspection/repair only for those breakers with moderate to significant wear. This becomes very significant when applied to high-voltage network multipole/multibreakers. By tracking each phase, the utility will need to inspect only those poles that trigger maintenance, instead of performing an internal inspection on all the poles. This greatly reduces the cost of maintaining high-voltage breaker-and-a-half schemes. Applying this technology to the higher voltage breakers first typically impacts the maintenance budget by 10 to 50%.

The utility designed other types of database queries by tying the operation data to the asset maintenance data. These queries made it possible to check for man-hours spent on a particular breaker or particular class of breakers to identify potential system problems, repeat problems with a particular breaker or class of beakers, or to correlate the performance of maintenance intervals and failures. These data are tied into the equipment tagging procedure so this information flows automatically into the maintenance database.

Monitoring the breaker air compressor contacts provides new data points to give early warning of impending compressor failures. By automatically counting the cycle time and integrating the total run time over a certain period, the utility identified maintenance needs and/or leaks resulting in excessive run time. Figure 4 is a plot showing the air compressor cycling.

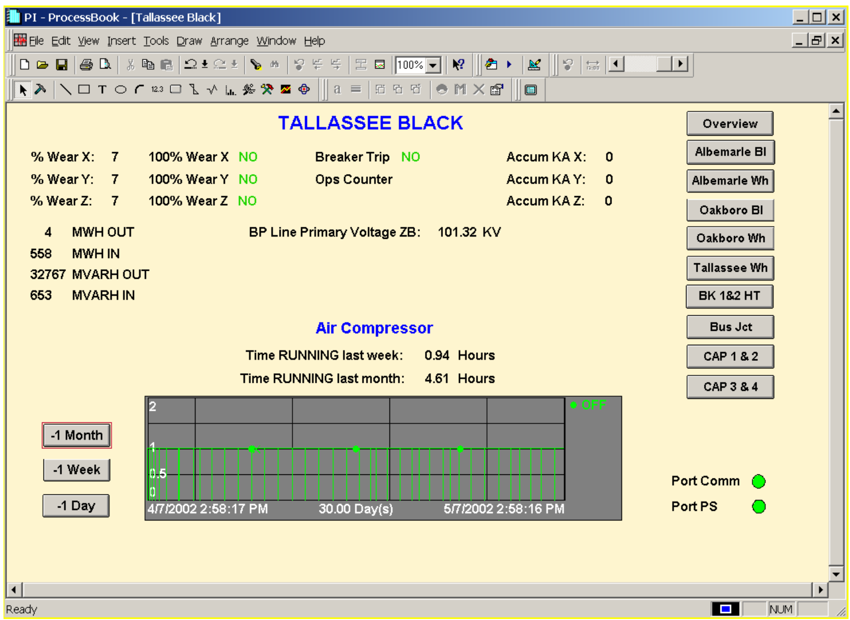


Figure 4 Breaker Air Compressor Monitoring Provides Early Warning of Impending Compressor Failures

Analysis of SF6 data by the utility revealed a small number of breakers experiencing SF6 leaks and requiring repair. SF6 pressure and temperature information in a database facilitated density calculations. Trended values over time provided change in density information that showed leakage that was automatically detected and corrected in the shortest possible time. Longer detection time of traditional methods results in wasting thousands of dollars worth of gas along with the environmental impact of the continued leaks. A typical business case analysis calculation consists of two breakers that leaked approximately 50% more this year than the previous year. The payback for these breakers is about 2.4 years using the previous year's leak rate. Using this year's leak rate, the payback time can be reduced to 1.6 years. This payback assumes full price for the replacement bushings.

CAPACITOR MONITORING

Table 4 Real-Time Performance Indicators Reduce Maintenance Costs

Traditional Data Points Available	Additional IED Data Points Available
Voltage	Fault Magnitude
Current	Operational Counter
Mvars	Bank Neutral
Bank Status	Targets
	86 CN & 62B Blocks
	86 F Reset
	Equipment Tagging
	Percent Rise Calculation

Trending voltage rise and fall based on capacitor operations provides real-time capacitor performance indicators. The utility found that monitoring capacitor cycle time and identifying control problems before customers and/or capacitor banks are damaged is easily achieved. This led to lower circuit beaker and switch maintenance costs. Capacitor rack imbalance can be monitored to trigger maintenance to rebalance and/or to measure capacitance before the rack trips. Figure 5 shows a typical capacitor operational screen from a PI database.

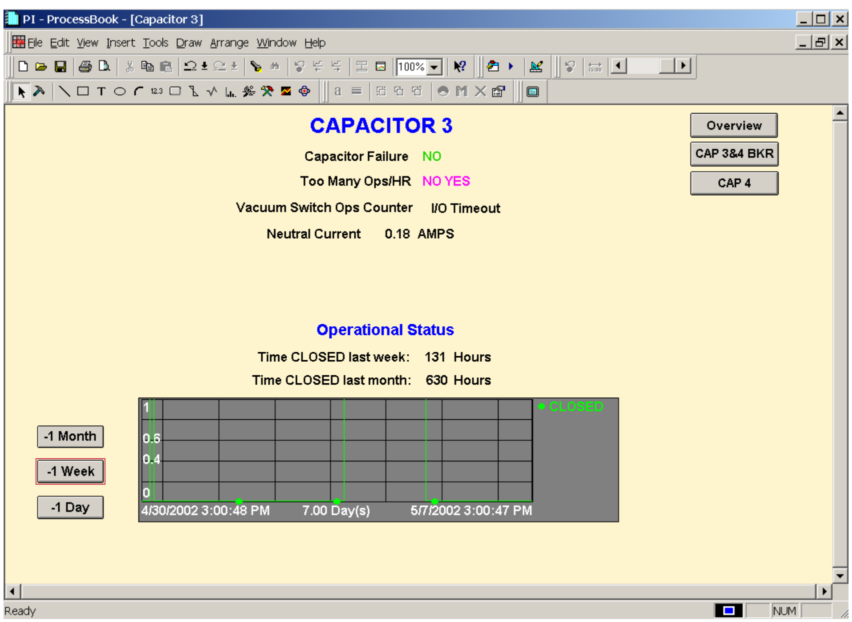


Figure 5 Typical Capacitor Operational Screen From a PI Database

BATTERY CHARGER MONITORING

Table 5 Battery Charger Monitoring Data Points

Traditional Data Points Available	Additional IED Data Points Available
Charger Alarm	AC Input Voltage
Positive Ground	DC Load Voltage
Negative Ground	DC Charger Voltage
	DC Load Current
	DC Charger Current
	DC Board Load
	Charger Failure
	High Charge Current
	Low Charge Current
	Asymmetry Alarm
	Temperature Alarm
	High Rate Alarm

When battery and charger systems are monitored, problems are identified early and solutions are quick and inexpensive. For example, an increase in dc board load signifies an impending equipment failure or additional substation equipment installed without proper sizing of the battery system. An asymmetry alarm provides early warning of a battery failure. By triggering maintenance appropriately, the battery system is fully functional when called upon to operate substation apparatus.

CONTROL HOUSE MONITORING

Table 6 Control House Monitoring Data Points

Traditional Data Points Available	Additional IED Data Points Available
Entry Alarm	Outdoor Temperature
Inside Temperature	Wind Speed
	Wind Direction
	Inside Humidity
	Outside Humidity
	Barometric Pressure
	Rain Gauge
	Station Service Status

Traditional Data Points Available	Additional IED Data Points Available
	Hydrogen Detector
	Dead Light Operation
	Yard Light Operation
	Fire Detection and Prevention System

In the past, not much emphasis has been placed on the actual control house building; however, the utility retrieved large amounts of data useful for detecting problems. For example, by implementing a hydrogen detector within the battery compartment, the utility received early warning of battery system failure with possible fire hazard and dealt with it before an explosion happened.

Real-time substation weather patterns are observed across the service area using local weather information from the control house. This aids in storm duty response and power system demand planning. Figure 6 shows the weather information available from the database.

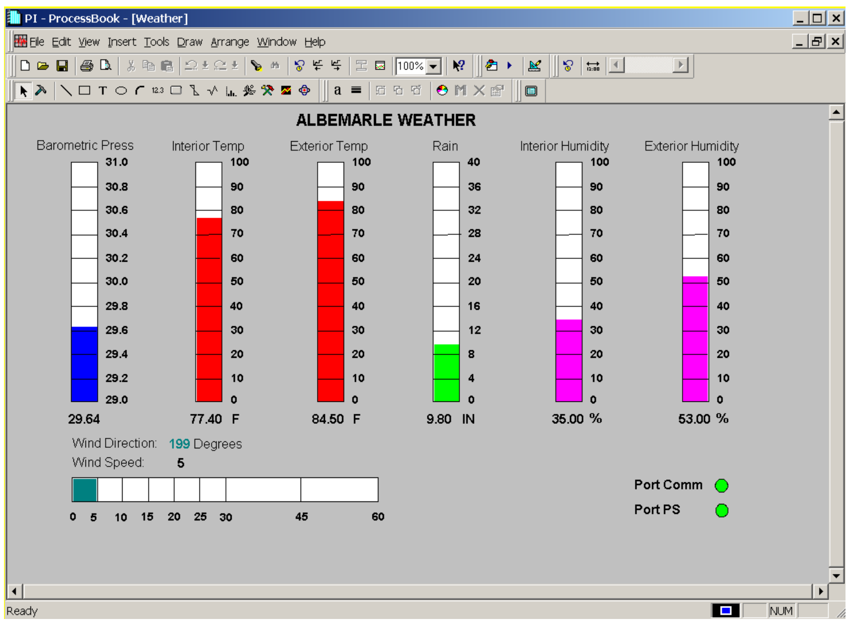


Figure 6 Control House Database Weather Information

APPLICATIONS

A protocol server supports both DDE and OPC data transfers. This utility chose Wonderware® for displaying a real-time graphical interface for monitoring and controlling the substations.

The substation computer performs several functions:

1. Runs a data collection server software application, which serves data from the substation communications processors to various support applications residing on the substation computer.

2. Provides storage of substation data using the Microsoft SQL Server, which is transferred to the corporate SQL server database.

3. Provides buffering of substation data and connection to the OSIsoft PI database.

4. Provides an operator interface for substation control and monitoring.

5. Provides substation monitoring and control to the control center as a backup to the SCADA system.

6. Runs tools to analyze relay event reports and runs utilities to aid in substation commissioning.

Current SCADA EMS systems are designed for operational control and monitoring and not for the massive amount of substation data available from modern microprocessor IEDs. Both a separate data path and an application were needed to support and make these data available to other databases and queries. The historical database chosen was PI from OSIsoft. This database is unique in that it intelligently processes and compresses the data, recording only those data that exceed an acceptable range of values. This method greatly reduces the required amount of stored data points. Other databases record every sample, regardless of whether that value changes; PI only stores samples when they change and only stores the delta. This provides a very robust and responsive database structure. The compression format permits rapid queries of data from a data store representing very long periods of archiving. The PI data are buffered on the substation computer. This provides uninterruptible data stream in the event of communications loss. PI data can be viewed using Microsoft Excel or PI ProcessBooks.

Microsoft SQL Server was chosen to provide SOE data storage and historical equipment tag information. These data are stored on the local computer and transferred daily to a corporate SQL server. This provides a convenient method to publish these data on a Web server.

Figure 7 shows a PI ProcessBook displaying Megawatts and Megavars from all the interties connected to a utility.

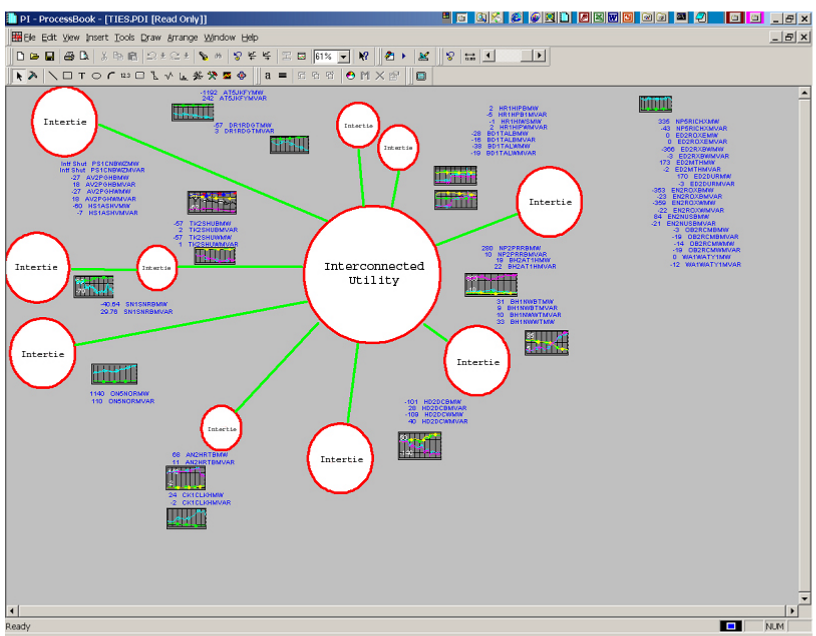


Figure 7 PI Process Book

Real-time operational data are displayed beside each graph in Figure 7. Clicking the graph opens a trend display presenting additional information. Figure 8 shows this display.

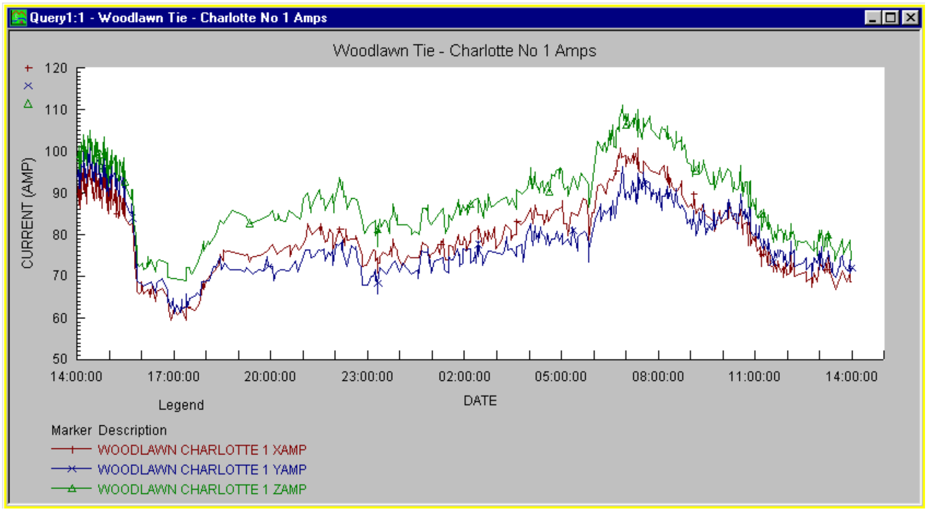
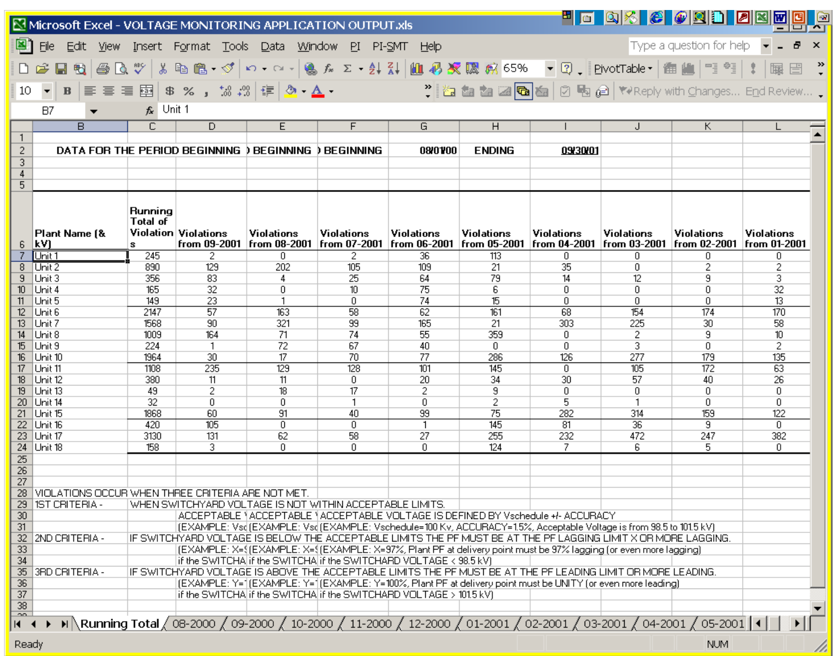


Figure 8 Trend Display

The utility wrote additional applications to take advantage of these data. Figure 9 shows a voltage monitoring table used to verify that interconnected generators are following their schedules. This application counts the frequency and severity of violations and provides real-time, continuous monitoring to ensure problems are found and corrected immediately.



Microsoft Excel - VOLTAGE MONITORING APPLICATION OUTPUT.xls

DATA FOR THE PERIOD BEGINNING 08/01/00 ENDING 09/30/01

Plant Name (& kV)	Running Total of Violations	Violations from 09-2001	Violations from 08-2001	Violations from 07-2001	Violations from 06-2001	Violations from 05-2001	Violations from 04-2001	Violations from 03-2001	Violations from 02-2001	Violations from 01-2001
Unit 1	245	2	0	2	36	113	0	0	0	0
Unit 2	890	129	202	105	109	21	35	0	2	2
Unit 3	356	83	4	25	64	79	14	12	9	3
Unit 4	165	32	0	10	75	6	0	0	0	32
Unit 5	149	23	1	0	74	15	0	0	0	13
Unit 6	2147	57	163	58	62	161	68	154	174	170
Unit 7	1568	90	321	99	165	21	303	225	30	58
Unit 8	1009	164	71	74	55	359	0	2	9	10
Unit 9	224	1	72	67	40	0	0	3	0	2
Unit 10	1964	30	17	70	77	286	126	277	179	135
Unit 11	1108	235	129	128	101	145	0	105	172	63
Unit 12	380	11	11	0	20	34	30	57	40	26
Unit 13	49	2	18	17	2	9	0	0	0	0
Unit 14	32	0	0	1	0	2	5	1	0	0
Unit 15	1868	60	91	40	99	75	282	314	159	122
Unit 16	420	105	0	0	1	145	81	36	9	0
Unit 17	3130	131	62	58	27	255	232	472	247	382
Unit 18	158	3	0	0	0	124	7	6	5	0

VIOLATIONS OCCUR WHEN THREE CRITERIA ARE NOT MET.

1ST CRITERIA - WHEN SWITCHYARD VOLTAGE IS NOT WITHIN ACCEPTABLE LIMITS.
ACCEPTABLE VOLTAGE IS DEFINED BY Vschedule +/- ACCURACY
(EXAMPLE: Vschedule=100 Kv, ACCURACY=1.5%, Acceptable Voltage is from 98.5 to 101.5 kV)

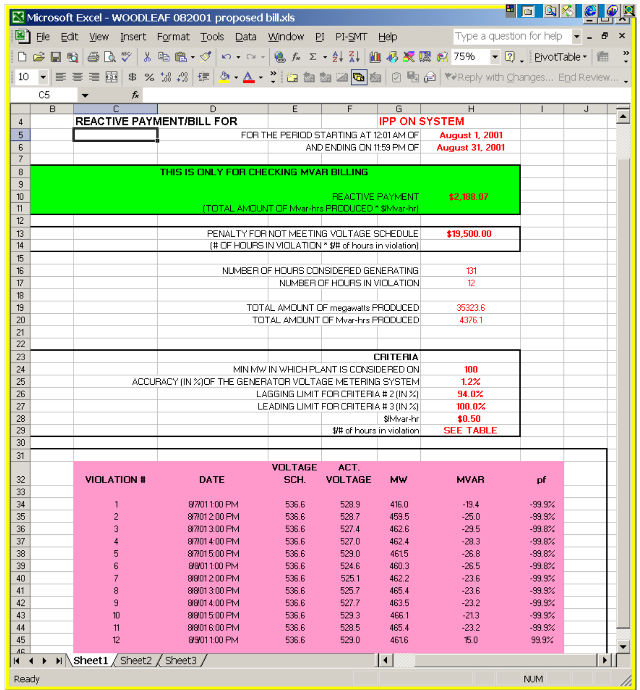
2ND CRITERIA - IF SWITCHYARD VOLTAGE IS BELOW THE ACCEPTABLE LIMITS THE PF MUST BE AT THE PF LAGGING LIMIT X OR MORE LAGGING.
(EXAMPLE: X=97%, Plant PF at delivery point must be 97% lagging (or even more lagging)
if the SWITCHARD VOLTAGE < 98.5 kV)

3RD CRITERIA - IF SWITCHYARD VOLTAGE IS ABOVE THE ACCEPTABLE LIMITS THE PF MUST BE AT THE PF LEADING LIMIT OR MORE LEADING.
(EXAMPLE: Y=100%, Plant PF at delivery point must be UNITY (or even more leading)
if the SWITCHARD VOLTAGE > 101.5 kV)

Running Total / 08-2000 / 09-2000 / 10-2000 / 11-2000 / 12-2000 / 01-2001 / 02-2001 / 03-2001 / 04-2001 / 05-2001

Figure 9 Voltage Monitoring Table

Tracking and trending the actual voltage versus the contract voltage schedule of the generators allows a penalty calculation to be developed when a violation occurs, as shown in Figure 10. This provides a complete history of the non-compliance schedules, including time, duration, and severity with the accumulated penalty charge associated for this non-compliance schedule.



Microsoft Excel - WOODLEAF 082001 proposed bill.xls

REACTIVE PAYMENT/BILL FOR IPP ON SYSTEM

FOR THE PERIOD STARTING AT 12:01 AM OF	August 1, 2001
AND ENDING ON 11:59 PM OF	August 31, 2001
THIS IS ONLY FOR CHECKING MVAR BILLING	
REACTIVE PAYMENT (TOTAL AMOUNT OF Mvar-hrs PRODUCED * $/Mvar-hr)	$2,188.07
PENALTY FOR NOT MEETING VOLTAGE SCHEDULE (# OF HOURS IN VIOLATION * $/# of hours in violation)	$19,500.00
NUMBER OF HOURS CONSIDERED GENERATING	131
NUMBER OF HOURS IN VIOLATION	12
TOTAL AMOUNT OF megawatts PRODUCED	35323.6
TOTAL AMOUNT OF Mvar-hrs PRODUCED	4376.1
CRITERIA	
MIN MW IN WHICH PLANT IS CONSIDERED ON	100
ACCURACY (IN %)OF THE GENERATOR VOLTAGE METERING SYSTEM	1.2%
LAGGING LIMIT FOR CRITERIA # 2 (IN %)	94.0%
LEADING LIMIT FOR CRITERIA # 3 (IN %)	100.0%
$/Mvar-hr	$0.50
$/# of hours in violation	SEE TABLE

VIOLATION #	DATE	VOLTAGE SCH.	ACT. VOLTAGE	MW	MVAR	pf
1	8/7/01 1:00 PM	536.6	528.9	416.0	-19.4	-99.9%
2	8/7/01 2:00 PM	536.6	528.7	459.5	-25.0	-99.9%
3	8/7/01 3:00 PM	536.6	527.4	462.6	-29.5	-99.8%
4	8/7/01 4:00 PM	536.6	527.0	462.4	-28.3	-99.8%
5	8/7/01 5:00 PM	536.6	529.0	461.5	-26.8	-99.8%
6	8/8/01 1:00 PM	536.6	524.6	460.3	-26.5	-99.8%
7	8/8/01 2:00 PM	536.6	525.1	462.2	-23.6	-99.9%
8	8/8/01 3:00 PM	536.6	525.7	465.4	-23.6	-99.9%
9	8/8/01 4:00 PM	536.6	527.7	463.5	-23.2	-99.9%
10	8/8/01 5:00 PM	536.6	529.3	466.1	-21.3	-99.9%
11	8/8/01 6:00 PM	536.6	528.5	465.4	-23.2	-99.9%
12	8/9/01 1:00 PM	536.6	529.0	461.6	15.0	99.9%

Figure 10 Penalty Calculation Table

Conclusion

In order to enhance the performance of existing systems and new designs, electric utilities must fully understand the current state of the power system as well as predict future capabilities and system expansion to increase reliability and performance. Increased global competition, deregulation, availability demands, and pricing pressures are forcing the electric utility industry to reduce operation costs while increasing reliability. Utilities often need to push equipment to higher loading levels to meet demands.

The main goal of improved data management and analysis is to better manage the use of power system apparatus. We need to move toward an asset management model that considers all three variables of health, availability/reliability, and performance along with appropriate economic drivers. The proposed application will not create a massive database; rather, it will leverage existing databases, including the real-time historian, and readily available communications processor technology to collect and integrate decision-making information. The I&C System can support direct access and links to the historian and other enterprise applications and will no longer be underused. Asset models may be as sophisticated or as simple as each end user prefers. Simple initial systems are easily expanded in the future as new requirements arise. One of many benefits of using an integration architecture built from microprocessor relays and communications processors for remote monitoring applications is the ability to add data points; usually with no additional hardware required. These additional data points are simply mapped in the communications processors, making them available to the remote monitoring program.

BIOGRAPHIES

Brian A. McDermott received his AS degree from Gaston College in 1981. He worked 22 years at Duke Power in various roles, the last one leading the Transmission Substation Automation Team. He joined Schweitzer Engineering Laboratories, Inc. in 2003 as an Integrated Systems Manager. In 2003 he was promoted to Director of Integrated Systems and leads the Systems and Services Division. He holds US Patent number 5,055,766, titled "Voltage Regulator Compensation in Power Distribution Circuits."

David J. Dolezilek received his BSEE from Montana State University in 1987. He worked as project engineer and manager for the Montana Power Company and the California Department of Water Resources prior to becoming self-employed as a control system consultant. He joined Schweitzer Engineering Laboratories, Inc. in 1996 as their first system integration engineer. Dolezilek became the Director for North American Sales in 1997, R&D Engineering Manager for Automation and Communications Engineering in 1998, and Automation Technology Manager in 2000, to research and design automated systems. In 2003, Dolezilek became Sales and Customer Service Technology Director. He is the author of numerous technical papers and continues to research and write about innovative design and implementation affecting our industry. Dolezilek participates in numerous working groups and technical committees. He is a member of the IEEE, the IEEE Reliability Society, Cigre WG 35.16, and the International Electrotechnical Commission (IEC) Technical Committee 57 tasked with global standardization of communication networks and systems in substations. He holds US Patent number 6,655,835, titled "Setting Free Resistive Temperature Device (RTD) Measuring Module."

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