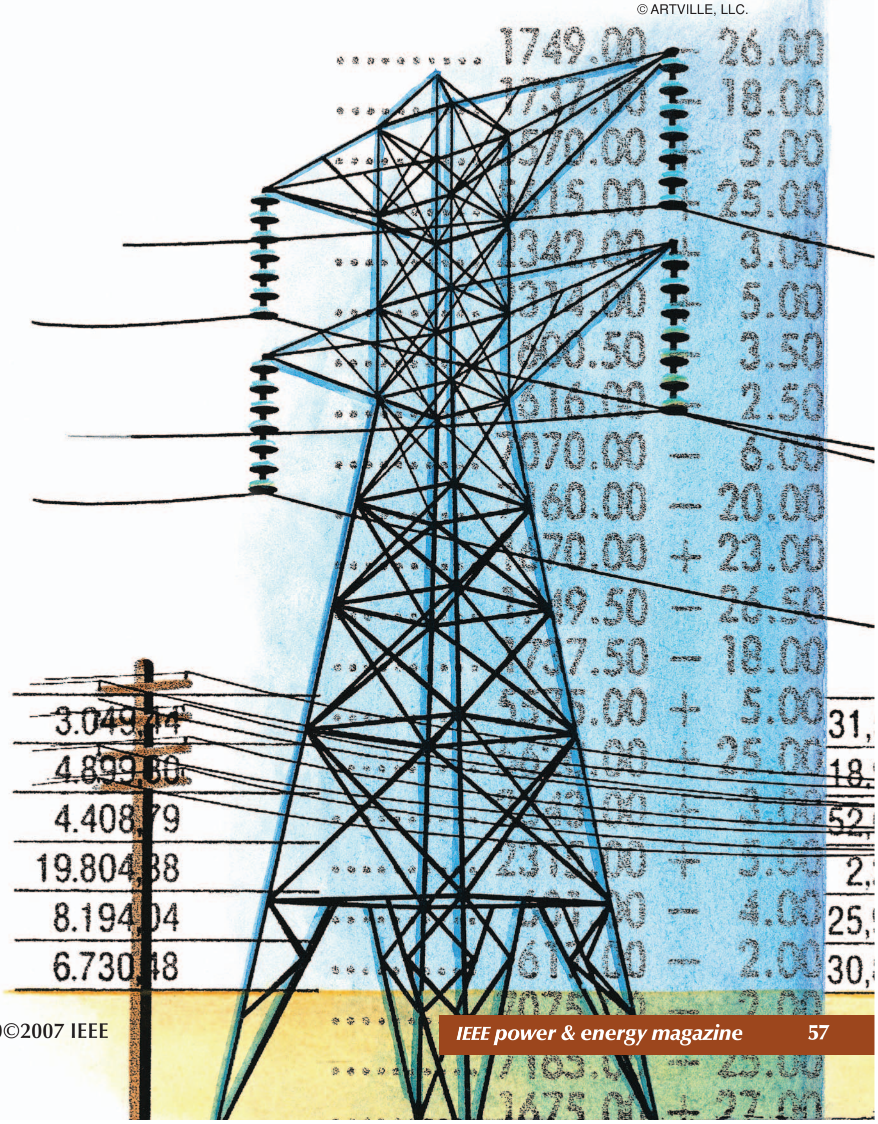
Realizing the Power of Data Marts

A Water and Power Utility Taps Nonoperational Data with a Power System Data Mart Project



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POWER UTILITIES HAVE ENJOYED predictable success at boosting system efficiency, reducing outages, and managing assets more effectively by investing in substation automation projects. But few utilities seem to realize they are short-changing their investment returns by failing to fully tap into the wealth of information collected by these automated components and delivering it to decision makers throughout the organization.

The ubiquity of this information gap is as unfortunate as it is unnecessary. Every utility that has implemented microprocessor-based devices and supervisory control and data acquisition (SCADA) technology has the ability to amass an incredibly detailed historical record of operational and nonoperational data relating to the performance of its generation,

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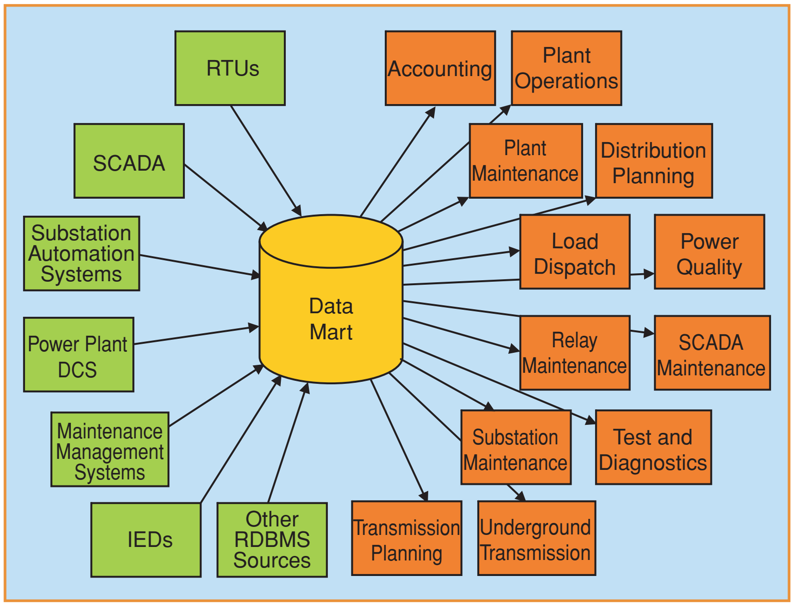


figure 1. Data mart architecture. Data flow into the data warehouse from all data sources and are available for desktop access to all users within the large number of user groups.

Operational Versus Nonoperational Data

Operational data are typical instantaneous values of volts, amps, watts, vars, and status changes that are conveyed continuously to the SCADA master station at a predefined scan rate utilizing the SCADA system communications protocol. Nonoperational data are the noninstantaneous information often used for historical and disturbance analysis purposes, such as fault event logs and oscillography, acquired from the IED using the IED vendor's proprietary ASCII commands acquired on demand or event triggered, but not continuously.

transmission, and distribution systems (see "Operational Versus Nonoperational Data").

Most automated systems have local archives only—known as historians—already built in. Typically, the local historians have not been designed for data mart integration with the ability to push data out to a central data warehouse, sometimes referred to as a corporate data mart, or have data pulled from them on demand.

The overall objective of data mart technology is to harness and integrate this valuable data, process the data into useable information, and serve the data to applications and personnel for analysis at all levels. When accurate, timely information regarding the performance of systems and equipment is available to personnel throughout the enterprise, everyone starts making better decisions, which benefits the entire organization. In addition, the utility is able to maintain assets more effectively by planning equipment upgrades and realizing longer life spans for aging components. The data mart also eliminates duplication of data residing in multiple databases in utility users' personal computers.

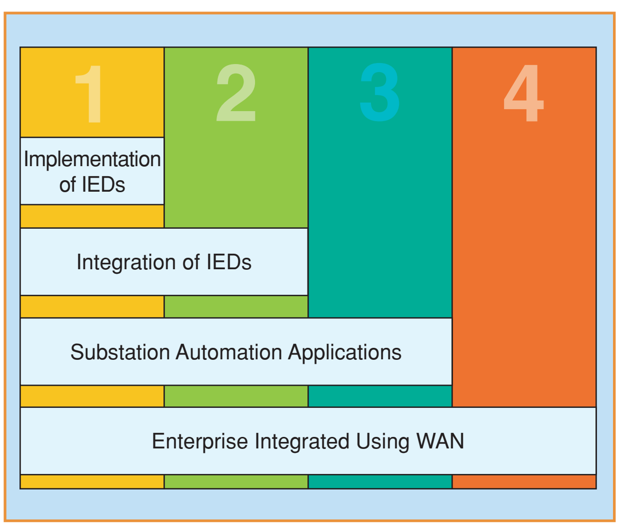


figure 2. Levels of integration. The data warehouse will be fully integrated with the maintenance management system to move to the stage of "Just-in-Time" condition-based maintenance.

Unfortunately, many utilities are unaware that data points describing virtually every function and event occurring in the generation, transmission, and distribution systems can be archived in these automated systems. Others may know this treasure trove of data exists but may not realize that technology is already available to unleash and utilize the information trapped inside. Fortunately, however, this information gap can be bridged with a corporate data mart, carefully designed data paths, and well-documented end-user information needs.

Introducing the Data Mart

The corporate data mart is a server or group of servers that retrieve data from the local data marts, which typically are linked to systems such as SCADA, substation automation, power plant distributed control systems, maintenance management, outage management, and customer information systems (see Figure 1). The corporate data warehouse accesses and stores these points and files centrally and integrates the data sets into unique information that is delivered to, or accessed when needed by, specific user groups in engineering, operations, and maintenance.

Few utilities have included data marts in their automation plans, primarily due to the lack of knowledge of the technology's availability, as noted above. Compounding this situation is the complexity involved in retrieving and integrating disparate data sets from various local data marts. The problem is that most utilities implement a variety of automated systems, and while SCADA systems operate today with more standardized data transfer communication protocols, the intelligent electronic devices (IEDs) in all other automated systems use proprietary ASCII commands to retrieve their nonoperational data. This means that a corporate data mart must be highly customized to communicate with each manufacturer's IED.

One utility that hasn't backed away from spanning the information gap is the largest municipally owned utility in the United States. To better serve its 3.8 million electric customers, the utility installed a new SCADA/energy management system (EMS) master station and is now replacing all remote terminal units (RTUs) with IEDs and substation automation systems under a US$101 million program referred to as the Energy Control System Upgrade Project (see "Program Scope: Detailed Summary").

On the surface, the upgrade looks like any other substation automation project, but in reality it may prove to be the blueprint for all future automation and integration programs using data mart technology. It differs from previous projects in that it has been designed and implemented from its inception around the data mart as a bridge between valuable power system information and over 20 well-defined user groups within the enterprise.

Revealing the Data Mart Model

This utility embraced the data mart concept in the late 1990s after reviewing the current state of technology in its substations and generation, transmission, and distribution systems. The utility quickly focused on a major problem—its legacy SCADA systems, RTUs, and electromechanical protective relays were each islands whose data could not be shared and integrated except by time-consuming manual methods. With plans in the works to upgrade some components, the utility began viewing the project as an automation *and* enterprise networking effort.

The utility decided to network its power system infrastructure in the same way it had networked its desktop computers. This will give personnel everywhere in the enterprise access to information they didn't have before, which will make them more productive.

The water and power company contracted an international utility consulting firm to assist in making the automation and networking plan a reality. The design called for creating a process whereby information will flow from power system monitoring equipment through nearly 10,000 IEDs in 182 substations over a new fiber-optic WAN and into a real-time corporate data mart. This centralized warehouse will provide secure access to analog, event, and status readings that are synchronized using global positioning system clocks to establish sequences of events leading up to incidents, such as outages.

Under the planned configuration, the operational data in the SCADA tells *what* has happened, and the integration of operational and nonoperational data from the IEDs will reveal *why* things happened.

Executives, management, analysts, and operational personnel will have access to the raw, as well as processed, data and integrated information using tailored third-party applications, linked spreadsheets, an intranet Web portal, and customized screens organized to display the data in the format best suited to support specific user group tasks. Users will have the ability to get up-to-the-minute readings, find peaks over various time periods, display alarm and status indicators, as well as view historical trends over any desired timeframe.

Program Scope: Detailed Summary

The Energy Control System Upgrade project described in this article will have included all of the following implementations and enhancements once it is completed:

- replacement of the SCADA/AGC master
- construction of a back-up control center
- connecting 179 substations through a fiber-optic WAN
- automation of 179 substations
- installation of 10,000 wireless micro-RTUs (2,700 capacitors, 250 switches, 7,000 fault recorders)
- automation of reactive power control
- establishing access between the enterprise information system and the energy control system.

The data mart project is basically a decision-support tool. Users will have the option of accessing the data on demand or having it fed to them on a time- or event-driven basis. Once the data are collected, the information will be analyzed by engineering and maintenance staff resulting in more effective resource planning and equipment operation.

The main challenge faced was designing a standard integration architecture that could meet specific needs, would be able to extract the desired operational and nonoperational data, and could deliver this data to users who have applications to analyze the information. Any utility considering a similar data mart project must address this same architecture issue, which essentially boils down to how the automation and integration should be carried out. Additionally, the developed architecture needs to be flexible and scaleable to accommodate future data sources.

A tremendous advantage is gained by having included data mart requirements in the initial substation automation system design, but utilities with automation already underway or completed can still tap into the data mart technology. Although these projects can get very complicated, most vendors of integration and automation equipment can retrofit their components with local data marts and customize them to provide data access via a corporate data warehouse. For technical details on the data mart now being deployed by this utility, see "Developing the Data Mart Architecture."

Designing the Right Architecture

Leveraging data mart technology requires the proper implementation of integration and automation early in the project planning cycle. The mistake too many utilities make is viewing integration and automation strictly as the installation of computerized monitoring and control devices in the substation. The crucial but often missing step is the integration of these devices and systems to the utility enterprise, focusing outside the substation as well as inside the substation. Without enterprise integration, the data mart concept fails to deliver the promised benefits.

For any automation project, utilities must understand that there are three levels of integration and automation (see Figure 2). Specific power equipment such as transformers and circuit breakers are installed in the power sys-

Developing the Data Mart Architecture

Providing improved access to information and fostering better informed decision making were the two drivers behind development of data mart architecture capable of serving all utility departments. The data mart was primarily meant to be a data collection and storage subsystem. As such, the utility required the data mart to:

- deliver reliable, accurate, and timely data to all users
- provide useful information from a vast amount of data
- perform data analysis as needed by end users
- deliver information in a user friendly interface.

General specifications called for the data mart to support a two-tier client/server or three-tier client/application/server architecture using the TCP/IP protocol. Open database connectivity (ODBC) support was required, with documented and demonstrated compatibility with Microsoft Access, Microsoft Excel, and other common front-end software. The data mart was required to support the EPRI Common Information Model (CIM) and be capable of representing objects typically contained in an electric power utility. The data mart shall support documenting the data using the Uniform Modeling Language (UML) standard.

In addition, the data mart had to collect data of the following types and make them available to users:

- sequence-of-events (SOE) data (time-tagged status points)
- substation equipment monitoring IED data
- disturbance data (fault event logs or files, oscillography)
- operational data (instantaneous values of volts, amps, etc., and status point changes)
- metering data
- relay test systems data
- dynamic line ratings
- energy pricing, regional loads, interface flows, and other congestion management data
- marketing data
- environmental (e.g., weather, hydrological, etc.) data.

The data mart was designed to relate disparate data types at a specific period in time from data collected and processed by various department systems. Examples of such data relations include IED operational data, IED nonoperational data, SOE data, SCADA historical data, and metering data. Through this integration, it shall be possible to easily recreate periods in history so that activities such as analyzing system disturbances and supporting dispute resolution can be handled efficiently.

To guarantee success, the utility specified that the data mart had to interface with numerous external and internal data sources. These interface specifications include the following:

- The data mart must interface with the SCADA system being installed at the energy control center. This interface is the most important because distribution planning, load dispatch, SCADA maintenance, substation maintenance, substation operations, and transmission planning will access data from the SCADA.
- Work orders must flow automatically from the MAXIMO maintenance management system to the data mart based on built-in business rules, such as scheduled maintenance and event-based

tem. The first level involves the implementation of IEDs, the microprocessor-based devices with two-way communication and computer processing capability that can monitor power system conditions and provide hundreds of points of operational data and a wealth of nonoperational data.

The IEDs are of paramount importance to the data mart information flow because they are implemented in protective relays, meters, transformers, circuit breakers, reclosers, load tap changer controls, voltage regulators, and nearly every other piece of power system equipment. What is essential to remember about IEDs is that they collect both operational and nonoperational data for storage in internal memories or local data marts.

maintenance. This interface must be a commercial off-the-shelf solution.

- The data mart must store selected data, such as emission and fuel usage rates, from the continuous emissions monitoring system. The data mart must provide access to this data and be capable of generating emissions compliance reports.
- The data mart must be integrated with substation automation systems at multiple locations so that analog, status, and alarm points related to substation operations, SCADA maintenance, and relay condition can be stored and made available to users.
- The data mart must be interfaced with the distribution automation system's data acquisition concentrator at the energy control center so that distribution automation analog, status, and alarm points can be stored and made available.
- The data mart must capture electric trouble reports so that personnel can access these in a user-friendly format.
- The data mart must capture results of relay tests generated by a relay testing system and stored in a Microsoft Access database.
- Analog, status, and alarm points must be stored in the data mart through integration with generation plant systems.
- The data mart must be integrated with the converter station systems.

Finally, the data mart has to able to generate reports and publish them in HTML, XML, PDF, delimited text, Postscript, and RTF formats to e-mail, Web browser, and file system destinations.

This utility is purchasing and installing hundreds of IEDs. The most common being implemented include:

- ✔ protective relays
- ✔ voltage regulators
- ✔ transformer temperature monitors
- ✔ transformer tap position monitors
- ✔ transformer-dissolved gas analyzers.

The second level is IED integration, and this is where most data mart projects get unintentionally derailed. Too often utilities only integrate the IEDs to provide a flow of operational data, which are the instantaneous values of voltage, current, and other data. But they fail to collect the nonoperational data, which are on-demand or event-triggered data of logs of events and oscillography. Nonoperational data provide extremely valuable information that enables operations and engineering groups in the utility to piece together the individual occurrences or conditions in multiple systems that led up to major events, such as outages or equipment failures. See the "For Further Reading" section at the end of this article for more information on leveraging nonoperational data.

The existing situation at this utility was typical—there were older RTUs that communicated hard-wired SCADA information to the SCADA master. There were also a few IEDs, but these were not integrated with any devices for remote access to operational data because the RTUs could not support it. A few substations had dial-up phone lines to provide remote access paths for certain individuals to access nonoperational data at specific IEDs.

Full IED integration means that the vendor establishes integration data paths in the system so that operational and nonoperational data can be accessed along specific data migration paths. This utility is now replacing the electromechanical devices with IEDs. The IEDs are being integrated so that operational data flow to the SCADA master and so that nonoperational data go to the corporate data warehouse. And every substation is being configured to allow personnel (with appropriate privilege) to remotely access any IED in the station.

The third level is substation automation applications. This involves the deployment of substation and feeder operating functions and applications including SCADA, alarm processing, automatic load restoration, and volt/var control. The most common is SCADA, which primarily monitors operational data points.

This utility currently has no plans for substation automation applications, but the new technology being implemented supports both utility-written and third-party automation applications. In a project of this type, the need for automation is typically driven by the results of data integration (i.e., being able to monitor the power system) and data analysis. As this information is processed and provided to the utility, its personnel will determine the applications they will write, or have written, for the substations. Utility personnel have already received training in writing and developing these applications.

The utility enterprise is above these three levels, and this usually involves overcoming the telecommunications challenges that currently prevent the free sharing and transmission of data to personnel in multiple departments. Solutions abound at this level, but many utilities choose to implement wide area networks (WANs) or intranet to move information between offices and among remote locations.

Establishing Three Data Paths

One IED can cost US$5,000 or more. By relying only on its ability to provide operational data, utilities are cheating themselves out of 80–90% of the IED's potential return on investment. The second key to automation and integration is establishing three data paths into and out of the substation to take full advantage of IED implementation. For most projects, it is the responsibility of the integration system vendor to program its product to communicate along these three paths.

Often referred to as the operational data path, the first is between the substation integration and automation systems

Making the Transition from Pilot to Production

In early 2004, after four years in the pilot phase, the utility began transitioning the Energy Control System Upgrade project to full production. By mid-2005, 14 substations had been upgraded with integrated IEDs, and another 17 were under implementation. About four substations will go into production each month until all 179 have been completed.

The water and power utility credits its quick transition to production to the fact that the upgrade contract called for the automation vendor to handle the production phase, assuming the pilot was a success. From the utility's perspective, too much time is lost in large automation projects when a separate bidding process must be conducted after the pilot is completed. In this case, the transition was nearly seamless.

The pilot itself involved seven prototypical substations in the same geographic area near the utility's engineering, maintenance, and testing headquarters. There were one receiving and five related distributing substations as well as one industrial substation serving a high-rise apartment building. These were chosen for the pilot because they were generally representative of typical utility facilities, and because they were convenient to the headquarters.

The pilot phase focused on many objectives including refining the templates that had been created to determine which data points will be extracted from the IEDs and connected to the SCADA and to the data mart. Each IED was treated as a stand-alone project in the pilot so that the best point configuration could be mapped for each and then duplicated in the template for actual production. These detailed designs and drawings changed numerous times throughout the testing phase.

Once production began and the automation components were built, the utility conducted factory acceptance tests at the vendor site. The factory acceptance tests centered on putting the system under the types of stress that might be encountered in the Los Angeles substations. The utility simulated the overloading and tripping that occurs during an earthquake or severe thunderstorm to make sure the system could still function. Many small problems were identified and fixed in the factory. The only major problem was CPU utilization that exceeded the 50% limit. This was also rectified.

Two important changes involving computer monitors were also made during the site acceptance tests in the substations. Throughout the planning and pilot phases, it was assumed that personnel in the substation could view the SCADA information on a single computer screen. Operators realized during the site acceptance tests that two monitors would be required to display all of the necessary information at once. Project specifications were rewritten for all substations to include two computer monitors.

The other issue encountered during site acceptance testing was the type of technical glitch that could only be uncovered in the substation. Each monitor was equipped with a KVM extender cable to link the terminal to the substation automation system. Perhaps from vibration or electromagnetic interference in the substation, the monitor screens suffered unacceptable flickers during operation. These were ultimately traced back to the extender cables. Fortunately, a more robust cable was procured, and the flicker was eliminated.

For the utility, site acceptance testing has also required timely installation of the new fiber optic network. This network provides the data communications link between the substation automation systems in the substations with the SCADA/EMS at the energy control center. This link must be live at the time of site acceptance testing to be sure the correct communications paths have been established using the selected DNP3 and the SCADA system. The SCADA can be programmed to scan automated devices in the substation every few seconds to retrieve instantaneous values of voltage, current, and other data. The operational data path is established for a continuous feed of data.

Several factors must be considered in leveraging this path. First, substation integration and automation systems must have the capability to interface with older SCADA systems and their proprietary protocols. Second, the bandwidth of the communications infrastructure chosen for this path must support requirements of the SCADA and the substation integration and automation system.

The second data path is more of a challenge. It involves gaining access to the nonoperational information in the IEDs that needs to be transferred to a corporate data warehouse. Each different device in the substation typically operates with a different protocol for this nonoperational data path. The data on this path are on-demand and nonperiodic, which means protocol issues are more complicated. Depending on user requirements, nonoperational data can be pushed from the substation to the warehouse or pulled from the substation through a warehouse application.

The third path is remote access, which allows a user at a location outside the substation to access the IEDs. With proper security and access privileges, the user might review device settings or actually change parameters, as well as download nonoperational IED data for analysis. Often called pass-through or loop-through, this communication path is typically a dial-up phone line or dedicated fiber-optic connection. The user dials into a secure modem, which then calls the user back if his or her phone number is approved. The user then dials a code to specify which device the communications link should be established with. Data flow between the caller and the device is two way.

Unless all three paths can be established, there is no point in implementing the corporate data warehouse because without these data streams only a limited number of users can be served, and even then, they will be receiving a selective and incomplete picture of conditions and events in the distribution network.

With assistance from the consulting firm in writing contract specifications and assisting in project management, the utility has implemented a new SCADA/EMS, completed the pilot phase of substation automation, and is in the production phase now. In addition, it has implemented a pilot phase for distribution automation and completed the data requirements matrix for the data mart and is in the early phases of implementing the data mart (see Figure 3).

Matching Data and Users

Successful data mart implementation relies heavily on the careful design of the technical architecture, but this project highlights the importance of a second equally critical component of the strategic plan—identifying the end users and defining their data needs at the enterprise level. No industry-standard approach has ever been developed to accomplish this, and the task is more difficult than might be expected.

With input from utility management, the consulting firm outlined a plan to ensure the data mart information would be fully exploited. The first step was identifying those personnel who needed data and information—the decision

protocol. In cases where the fiber laying is not keeping up with automation, the utility has established temporary Ethernet communication links using copper lines. To date, only one site acceptance test has been unexpectedly delayed due to a construction holdup of fiber outside the station.

With most of the technical problems ironed out in the pilot phase, factory acceptance tests, and site acceptance tests, the remaining implementation challenges are logistical. Perhaps the most significant is that the utility operates substations ranging in age from just-built to over 80 years old, each with very different designs and layouts. While the racks of automation equipment being installed are standardized, the stations are not, and every installation has differed from the previous. Some substations have plenty of room for the extra racks, while others must have older components removed to accommodate the new equipment. A few substations have even had to undergo asbestos remediation and lead cable removal before the upgrade could occur.

From a planning perspective, the other challenge is the assignment of construction laborers, electricians, and testers who are required to complete each implementation. As the utility moves forward with the upgrade, several other projects are also ongoing. This means that personnel must be coordinated, and outside staff must be contracted to keep the project on schedule. During the production phase, the utility is trying to keep five crews busy, each concentrating on a different substation. And these facilities must be selected in unrelated areas so that service disturbances are avoided.

So far, the average production automation has taken five to six months depending on the size of the substation. The implementation pace accelerated so that 35–40 stations are completed annually.

Many utilities are unaware that data points describing virtually every function and event occurring in the generation, transmission, and distribution systems can be archived in these automated systems.

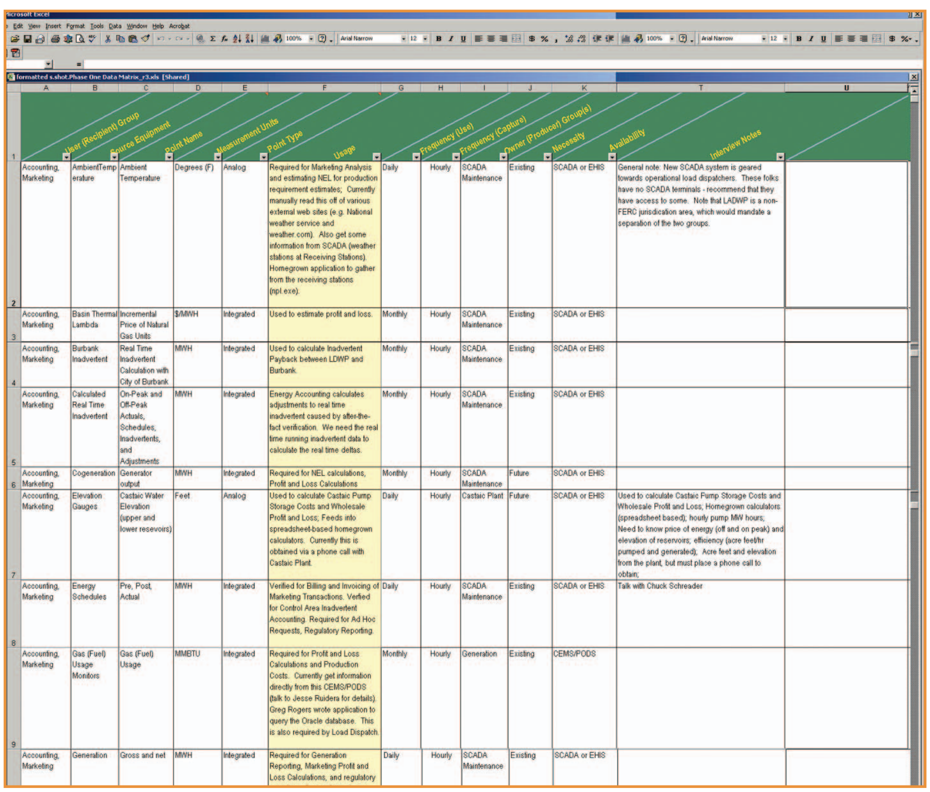
makers. Rather than lump these individuals into their predefined departments, the consulting firm suggested grouping the users into informal clusters based on job function, applying the notion that similar functions require the same information.

This concept proved quite successful. The utility identified more than 20 user groups for whom data would be collected, integrated, and delivered. These groups include personnel involved in distribution planning, transmission planning, substation operations, load dispatch, relay maintenance, power supply operations, substation design, and other functions.

Once the end users had been identified, the consulting firm performed a series of interviews with the individuals in an attempt to reveal their data and information needs. The questions focused on the type of data and reports each person currently used and what information they could benefit from accessing in the future. In some cases, the end users could name the specific data sets they wanted. These most often had existing desktop applications that they wanted populated with new or different data for processing and analysis.

Other personnel who were less familiar with nonoperational data identified their needs in terms of the information they wanted or the source equipment they wanted to tap. It was then up to the consultants to work backward and define the various nonoperational and/or operational data sets that could be integrated and processed to yield the desired results.

After the necessary data sets had been defined, the interview sessions progressed toward gathering more minute details, such as the frequency, accuracy, formatting, and timeliness with which the data must be collected, delivered, and used. Ultimately, the consulting firm devised a matrix that matched each user group with its data requirements and described how the data would be processed and applied.



	User (Recipient) Group	Source Equipment	Point Name	Measurement Units	Point Type	Usage	Frequency (Use)	Frequency (Capture)	Owner (Producer) Group(s)	Necessity	Availability	Interview Notes	
2	Accounting, Marketing	AmbientTemperature	Ambient Temperature	Degrees (F)	Analog	Required for Marketing Analysis and estimating NEL for production requirement estimates; Currently manually read this off of various external web sites (e.g. National weather service and weather.com). Also get some information from SCADA (weather stations at Receiving Stations). Homegrown application to gather from the receiving stations (npl.exe).	Daily	Hourly	SCADA Maintenance	Existing	SCADA or EHIS	General note: New SCADA system is geared towards operational load dispatchers. These folks have no SCADA terminals - recommend that they have access to some. Note that LADWP is a non-FERC jurisdication area, which would mandate a separation of the two groups.	
3	Accounting, Marketing	Basin Thermal Lambda	Incremental Price of Natural Gas Units	$/MWH	Integrated	Used to estimate profit and loss.	Monthly	Hourly	SCADA Maintenance	Existing	SCADA or EHIS		
4	Accounting, Marketing	Burbank Inadvertent	Real Time Inadvertent Calculation with City of Burbank	MWH	Integrated	Used to calculate Inadvertent Payback between LDWP and Burbank.	Monthly	Hourly	SCADA Maintenance	Existing	SCADA or EHIS		
5	Accounting, Marketing	Calculated Real Time Inadvertent	On-Peak and Off-Peak Actuals, Schedules, Inadvertents, and Adjustments	MWH	Integrated	Energy Accounting calculates adjustments to real time inadvertent caused by after-the-fact verification. We need the real time running inadvertent data to calculate the real time deltas.	Monthly	Hourly	SCADA Maintenance	Existing	SCADA or EHIS		
6	Accounting, Marketing	Cogeneration	Generator output	MWH	Integrated	Required for NEL calculations, Profit and Loss Calculations	Monthly	Hourly	SCADA Maintenance	Future	SCADA or EHIS		
7	Accounting, Marketing	Elevation Gauges	Castaic Water Elevation (upper and lower resevoirs)	Feet	Analog	Used to calculate Castaic Pump Storage Costs and Wholesale Profit and Loss; Feeds into spreadsheet-based homegrown calculators. Currently this is obtained via a phone call with Castaic Plant.	Daily	Hourly	Castaic Plant	Future	SCADA or EHIS	Used to calculate Castaic Pump Storage Costs and Wholesale Profit and Loss; Homegrown calculators (spreadsheet based); hourly pump MW hours; Need to know price of energy (off and on peak) and elevation of reservoirs; efficiency (acre feet/hr pumped and generated); Acre feet and elevation from the plant, but must place a phone call to obtain;	
8	Accounting, Marketing	Energy Schedules	Pre, Post, Actual	MWH	Integrated	Verified for Billing and Invoicing of Marketing Transactions. Verfied for Control Area Inadvertent Accounting. Required for Ad Hoc Requests, Regulatory Reporting.	Daily	Hourly	SCADA Maintenance	Existing	SCADA or EHIS	Talk with Chuck Schreader	
9	Accounting, Marketing	Gas (Fuel) Usage Monitors	Gas (Fuel) Usage	MMBTU	Integrated	Required for Profit and Loss Calculations and Production Costs. Currently get information directly from this CEMS/PODS (talk to Jesse Ruidera for details). Greg Rogers wrote application to query the Oracle database. This is also required by Load Dispatch.	Monthly	Hourly	Generation	Existing	CEMS/PODS		
	Accounting, Marketing	Generation	Gross and net	MWH	Integrated	Required for Generation Reporting, Marketing Profit and Loss Calculations, and regulatory	Daily	Hourly	SCADA Maintenance	Existing	SCADA or EHIS		

figure 3. Data requirements matrix. Sample screen shot of a portion of the data requirements matrix. The matrix will drive not only the data collection requirements of the data warehouse but also the information presentation to the user groups.

Putting the Matrix into Action

Based on the results of the data-use matrix, project participants customize the data warehouse. Configuration involves tailoring the data warehouse to access the necessary data files, integrate them into specified combinations, and deliver the output to the right users via the new WAN.

A crucial part of this programming step is determining which data the warehouse can process internally and which raw data it should deliver to existing third-party applications for processing and analysis. This configuration phase is underscoring the fact that not all data sets can be integrated and processed in the data warehouse and may

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require the purchase and installation of new add-on application programs to output useful information.

Dashboard-type interfaces will be designed for each of the user groups to make it easy for them to access their relevant information on demand from the data mart. Current plans also include the interfacing of the data mart with the utility's maintenance management system. This will facilitate "Just-In-Time" maintenance using the real-time operational and nonoperational data from the warehouse. By performing equipment condition-based maintenance using actual runtime and operating parameters from the plant, maintenance work orders will be automatically triggered in the plant maintenance systems by the data mart interface (see Figure 4).

With the ever-increasing focus on environmental regulations and compliance, the warehouse will also be interfaced with the continuous emission monitoring system (CEMS) within the utility. Emissions data will be retrieved using a driver and stored in the data mart for immediate access. Emissions compliance reports will be generated from the data mart by the end users.

Data mining tools will be provided to the users at their client workstations to help analyze the historical operational and nonoperational data and provide actionable information, so that users will be able to make more informed decisions that will directly cut operating costs, reduce outages, and improve the plant asset optimization.

The availability of historical data will greatly enhance the ability of the operations personnel to perform event-and-disturbance analysis on an as-needed basis. Once these new data sets are available, engineering, maintenance, and operations staff will be able to build new applications on top of the data mart that were not possible before.

The utility considers data security a paramount requirement of the overall data warehouse system. Data will be accessible to the user groups only on an as-needed basis, and strict data security controls will be established to ensure the reliability and accuracy of the data within the warehouse.

For example, a built-in firewall in the data mart ensures the validity of the username and password before granting access to any of the data within the warehouse. The warehouse will have multiple security levels of user access, and the access level of the user is also determined by the firewall based on a user assigned user assignment.

In addition, a viewer will be used to perform security audits of the system as needed by the data mart system administrators. To ensure security and reliability, the data within the data warehouse system will be archived on a regular basis by the system administrator.

Production began in late 2004. Local data marts are linked to the central data warehouse as IED implementation and integration are completed. Construction of the fiber-optic WAN will likely be completed on the same time schedule. About 7% of the total fiber line has been laid. See "Making the Transition from Pilot to Production" for the current project status.

Anticipated returns on investment from the SCADA replacement and substation automation have been clearly quantified in the Energy Control System Upgrade Project, but it's much harder to put an absolute value on the benefit of accessing nonoperational data because it has never done before; however, this may be the greatest windfall of the entire project.

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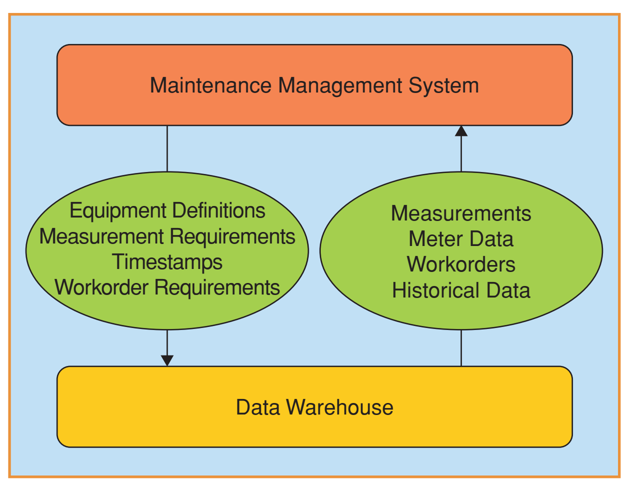

figure 4. Integration with the maintenance management system. Typical levels of integration within the enterprise based on various stages of technological development.

What is essential to remember about IEDs is that they collect both operational and nonoperational data for storage in internal memories or local data marts.

of Clearwater, Florida, which is providing the substation and IED integration solution under subcontract to Convergent Group (now Enspiria Solutions).

For Further Reading

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