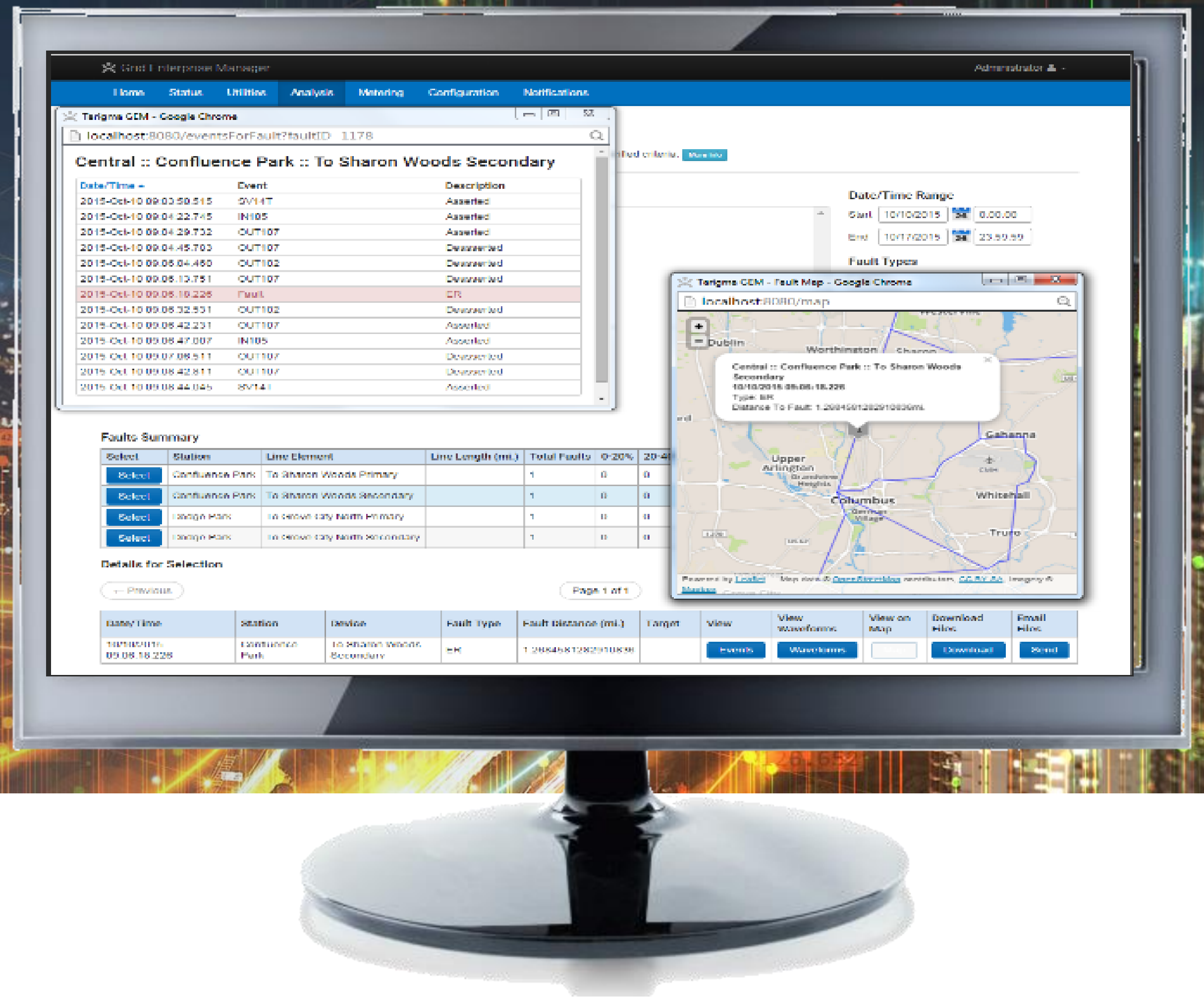
GE Renewable Energy
Grid Solutions

Big Data, IoT, Enterprise Data Management, and the New Data Requirements of Drones and Robotic Inspection Devices



Presented by: John D. McDonald, P.E.
Smart Grid Business Development Leader

Speaker Biography

John D. McDonald, P.E. (johnd.mcdonald@ge.com)

Smart Grid Business Development Leader
GE Grid Solutions

- BSEE (1973), MSEE (1974) - Purdue University
- MBA (Finance) (1978) – University of California-Berkeley
- 46 years full-time work experience in electric power system automation (i.e., Smart Grid)
- Worked for 4 automation system suppliers & 2 international consultants (12 years at GE)
- Written 150 papers and articles, co-authored five books, one US Patent
- IEEE Life Fellow (IEEE member for 49 years)
- IEEE Power & Energy Society (PES) Substations Committee Chair (2001-2002)
- IEEE PES President (2006-2007)
- IEEE Division VII Director (2008-2009)
- IEEE-SA Board of Governors (2010-2011)
- IEEE PES Distinguished Lecturer (since 1999)
- IEEE Global Public Policy Committee (GPPC) member (2017-2020)
- IEEE Foundation Director-Elect (2020)
- 2009 Purdue University Outstanding Electrical and Computer Engineer

Agenda

- Key Industry / Societal Trends
- Grid Operations: Types of Data
- IoT and New Software Analytics
- IT/OT Convergence and Enterprise Data Management
- Grid Modernization Standards: Development and Interoperability
- New Sources of Data – Unmanned Aerial Vehicles (UAVs) and Robotics

Key Industry / Societal Trends

Key Industry / Societal Trends

- Transitioning from Devices / Systems to Holistic Solutions
- Success = Technology, Standards, Policy
- Culture => Closed Loop Control, Distributed Intelligence
- Grid Resiliency => Microgrids
- Big Data, Observability Strategy, Analytics, User Experience
- Convergence of IT and OT
- ADMS Project Costs => 30% ADMS Cost, 70% Integration Costs
- Strong Grid (Communications Infrastructure, IT Infrastructure) before Smart Grid

Grid Operations: **Types of Data**

Types of Data: “Operational” Data

- Data that represents the **real-time status, performance, and loading** of power system equipment
- This is the **fundamental information used by system operators** to monitor and control the power system

Examples:

- Circuit breaker open/closed status
- Line current (amperes)
- Bus voltages
- Transformer loading (real and reactive power)
- Substation alarms (high temperature, low pressure, intrusion)

Types of Data: "Non-Operational" Data

- Data items for which the **primary user is someone other than the system operators** (engineering, maintenance, etc.)
- Note that operators are usually interested in some data that is classified as non-operational

Examples of "Non-Operational" data:

- Digital fault recorder records (waveforms) (protection engineer)
- Circuit breaker contact wear indicator (maintenance)
- Dissolved gas/moisture content in oil (maintenance)

Characteristics of Operational & Non-Operational Data

Characteristic	Operational Data	Non-Operational Data
Data Format	Usually limited to **individual time-sequenced data items**	**Usually a data file** that consists of a collection of related data elements
Real Time vs Historical	Usually consists of **real-time or near real-time** quantities	Mostly **historical** data: trends over time
Data Integration	Easily transportable by conventional SCADA RTUs using **standard (non-proprietary) protocols**	Typically use **vendor specific (proprietary) formats** that are not easily transported by SCADA communication protocols

IoT and **New Software** Analytics

Drones, Robots and IoT: A Data Management Opportunity for Utilities

Internet of Things (IoT)

Drive the next productivity revolution by connecting intelligent machines with people at work

The "IoT" Connects...

1 Intelligent Machines

Leverage technology & communication to cost-effectively connect machines

\+

2 Big Data & Analytics

Combine the power of big data, big analytics, and industry physics

\+

3 People at Work

Connecting people any place, any way, and any time for intelligent operations

A world that works better, faster, safer, cleaner and cheaper

Energy Value:

Global Energy
Capex $1.9T/year

→

The first 1% annual savings equals $300B over 15 years

New Software Analytics Development Areas

Meter Insight

- Revenue Protection
- Power Quality and Reliability
- Load Forecasting and Research

Outage Insight

- Automated KPI data validation
- Dynamic KPI dashboards
- Outage Event Recorder
- Planned outage optimization
- Predictive Outage Analytics
- Accurate ETR

Six Sigma

Reliability Insight

- Predictive vegetation management
- Asset health analysis
- System health analysis
- Lifecycle analysis and portfolio optimization

Renewables Insight

- PV load (dis)aggregation/ hotspot analysis
- Wind load (dis)aggregation and hotspot analysis
- EV penetration/ impact analysis
- DER load orchestration

Consumer Insight

- Social media integration
- Customer Segmentation
- Customer Engagement
- Sentiment Analysis

IT/OT Convergence & Enterprise **Data Management**

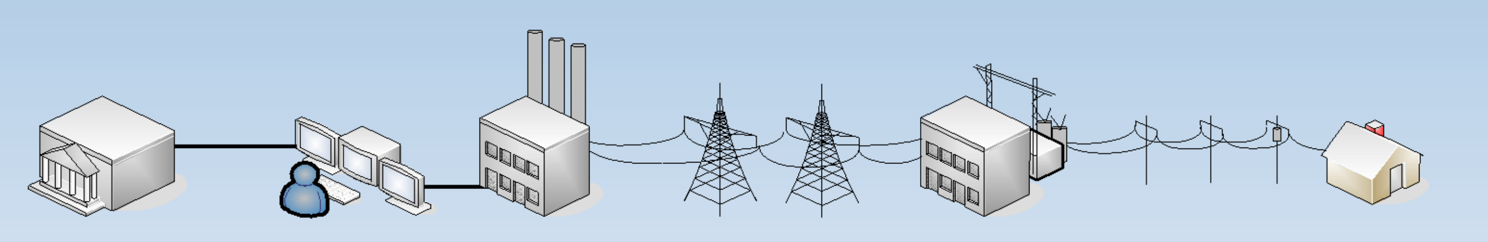
Drones, Robots and IoT: A Data Management Opportunity for Utilities

IT/OT Convergence: Grid Modernization

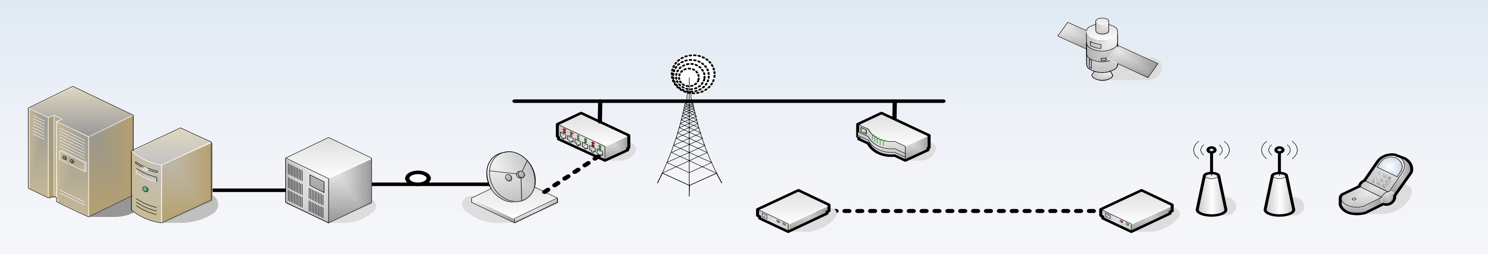
Integration of electrical and information infrastructures with automation and information technologies within our existing electrical network

Comprehensive solutions that:

- Improve power reliability, operational performance and overall productivity
- Deliver increases in energy efficiencies and decreases in carbon emissions
- Empower consumers to manage their energy usage and save money without compromising their lifestyle
- Optimize renewable energy integration and enable broader penetration



Electrical infrastructure

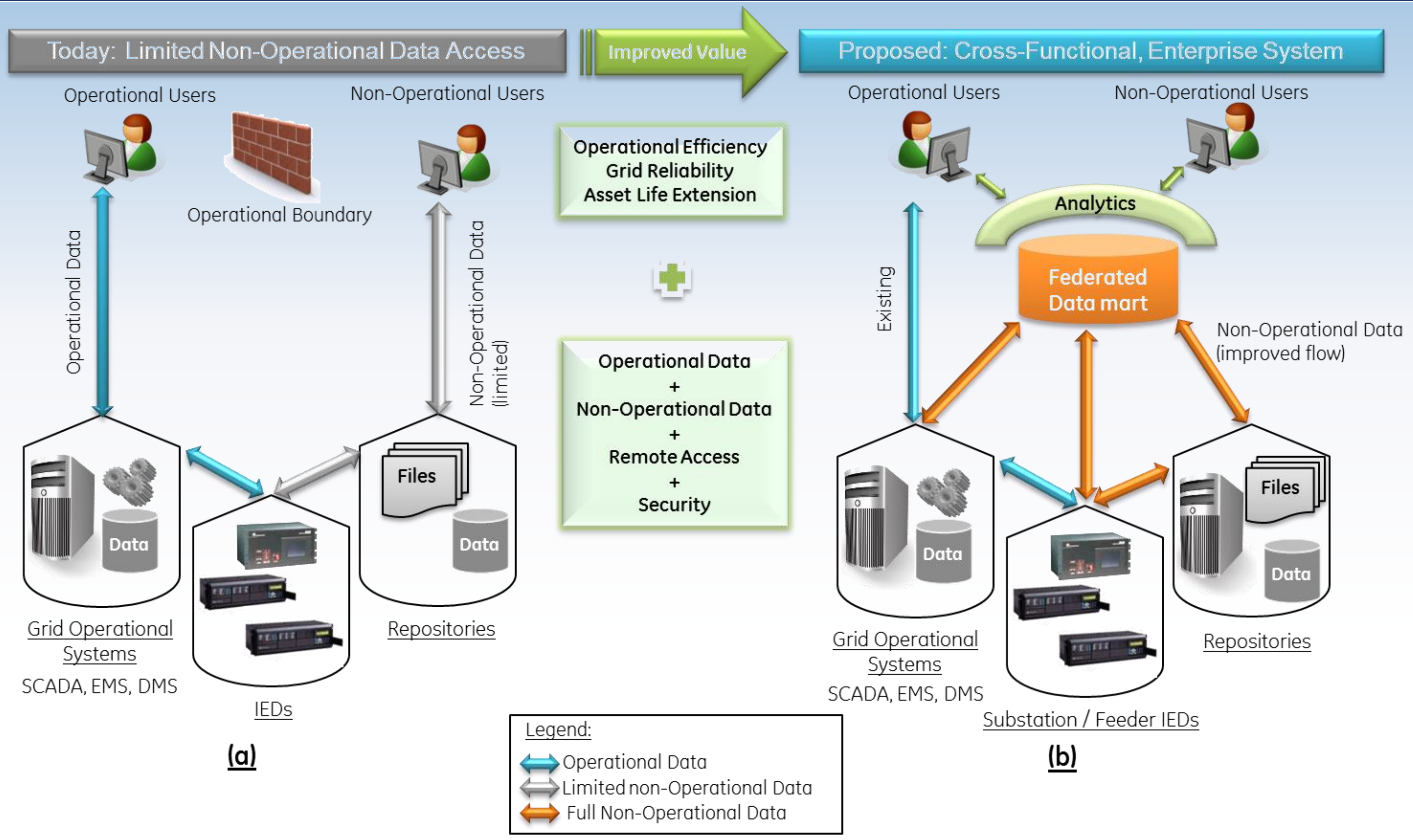


Information infrastructure

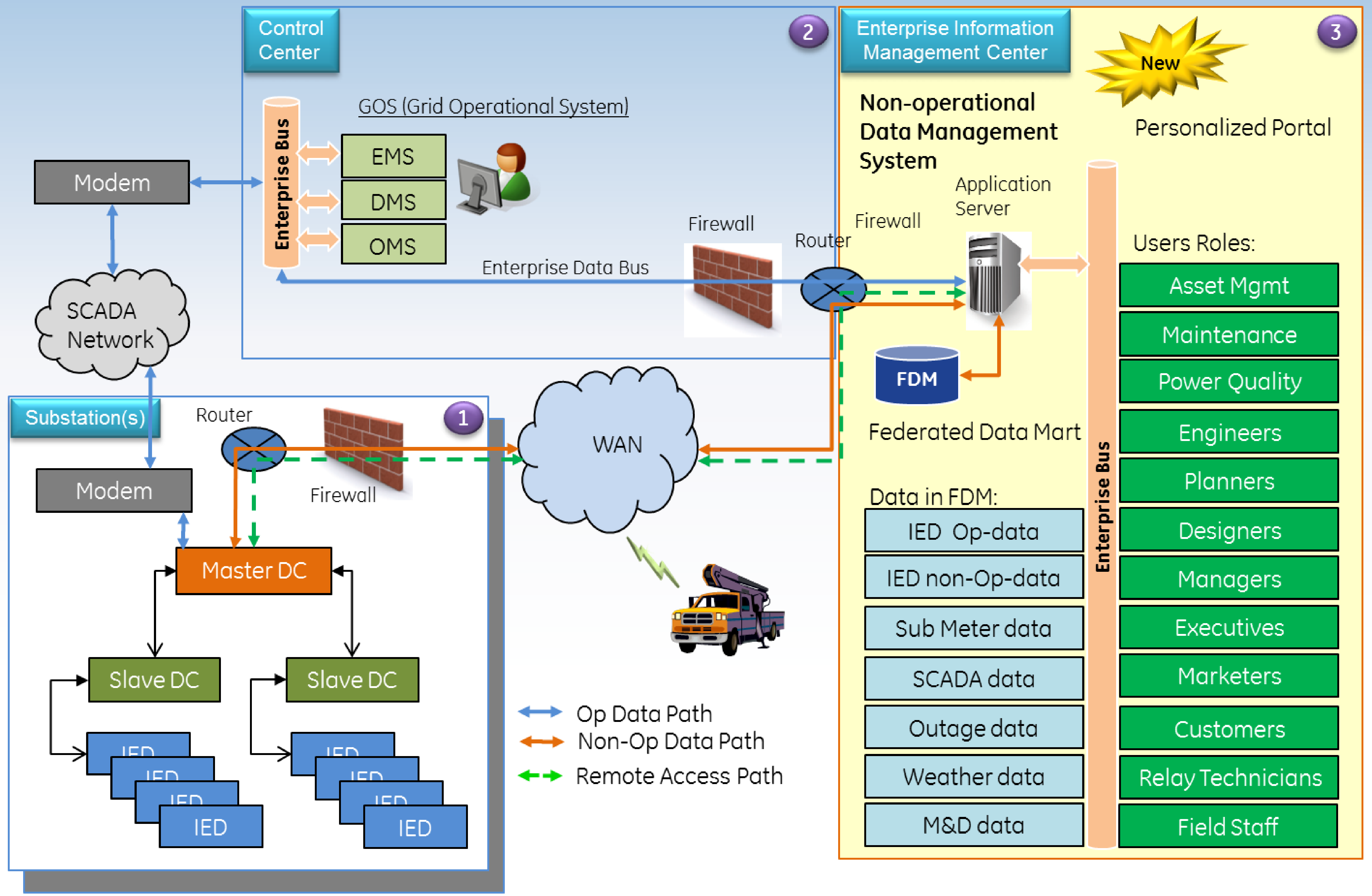
That deliver meaningful, measurable and sustainable benefits to the utility, the consumer, the economy and the environment

More Focus on the Distribution System

IT/OT Convergence and Data Access



Realizing Greater Value from Data



Project Steps

- Workshop to bring utility stakeholders to the same level in enterprise data management
- Review the data maps of all IEDs, systems and repositories and create standard data templates
- Develop enterprise data requirements matrix (map data points of value to stakeholder group(s) that will use the data)
- Review substation automation architectures to extract data points of value, concentrate the points, and send across firewall to enterprise data mart on corporate network

Grid Modernization Standards:
Development & Interoperability

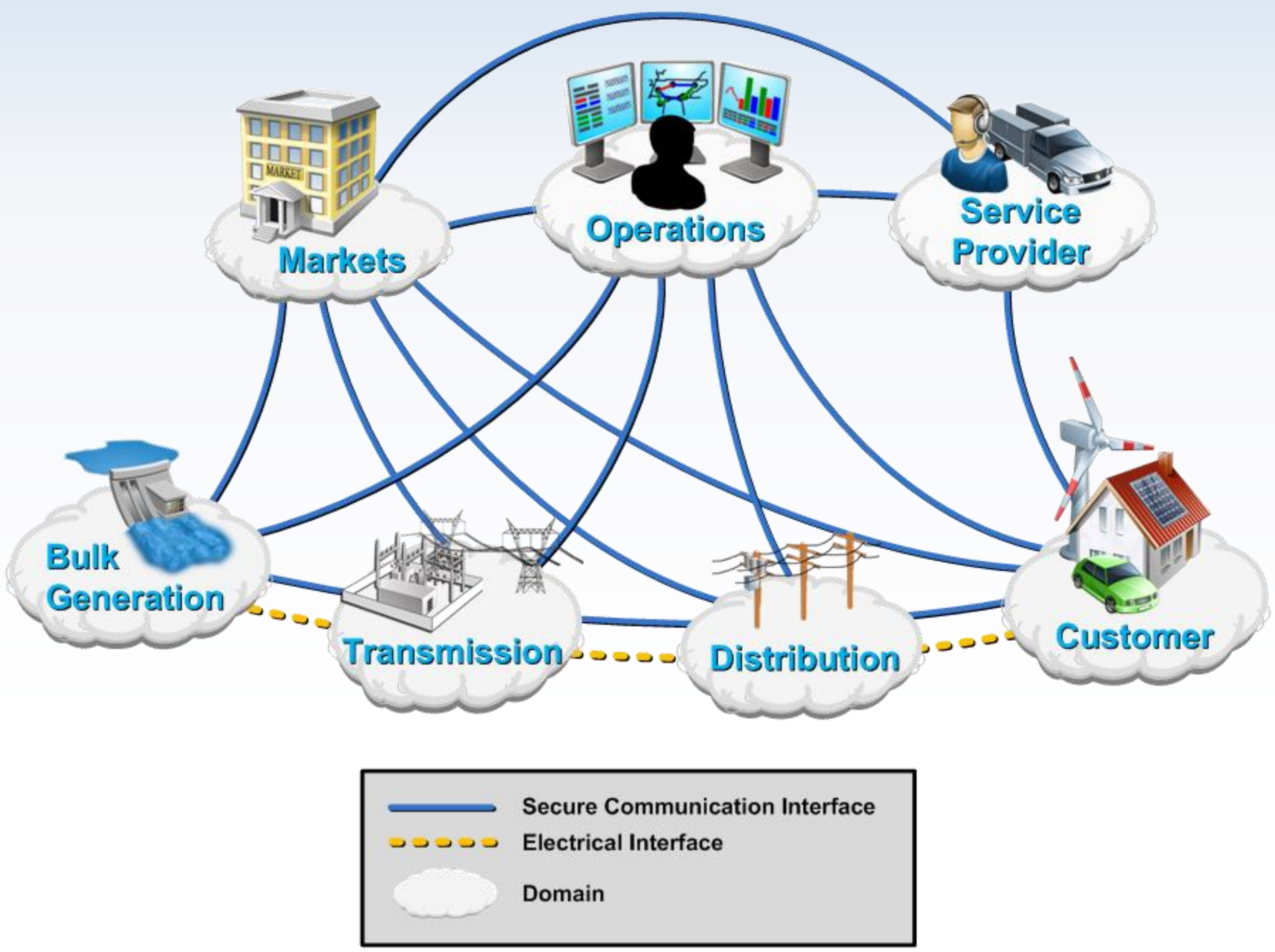
Drones, Robots and IoT: A Data Management Opportunity for Utilities

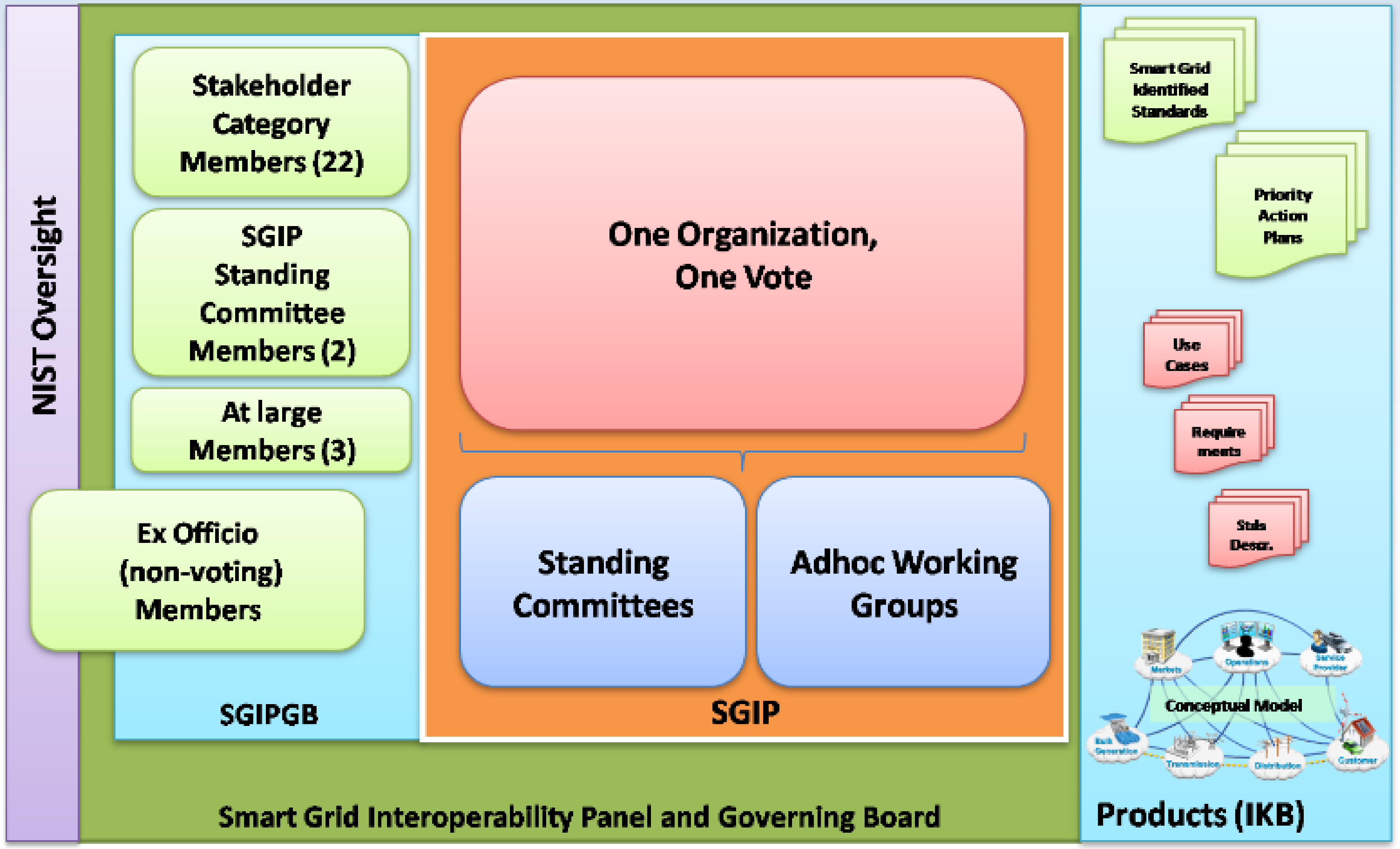
Example: Standards Framework

National Institute of Standards and Technology (NIST)

... Smart Grid Conceptual Reference Model

... Smart Grid Interoperability Panel Organizational Structure





NIST: Smart Grid Interoperability Standards

Release 1.0 Standards Identified for NIST Interoperability Framework

Standard	Application
AMI-SEC System Security Requirements	Advanced metering infrastructure (AMI) and Smart Grid end-to-end security
ANSI C12.19/MC1219	Revenue metering information model
BACnet ANSI ASHRAE 135-2008/ ISO 16484-5	Building automation
DNP3	Substation and feeder device automation
IEC 60870-6 / TASE.2	Inter-control center communications
IEC 61850	Substation automation and protection
IEC 61968/61970	Application level energy management system interfaces
IEC 62351 Parts 1-8	Information security for power system control operations
IEEE C37.118	Phasor measurement unit (PMU) communications
IEEE 1547	Physical and electrical interconnections between utility and distributed generation (DG)
IEEE 1686-2007	Security for intelligent electronic devices (IEDs)
NERC CIP 002-009	Cyber security standards for the bulk power system
NIST Special Publication (SP) 800-53, NIST SP 800-82	Cyber security standards and guidelines for federal information systems, including those for the bulk power system
Open Automated Demand Response (Open ADR)	Price responsive and direct load control
OpenHAN	Home Area Network device communication, measurement, and control
ZigBee/HomePlug Smart Energy Profile	Home Area Network (HAN) Device Communications and Information Model

- IEEE had identified over 100 standards involved in Smart Grid.
- IEC had identified over 100 standards involved in Smart Grid.
- NIST and the Smart Grid Interoperability Panel (SGIP) reduced the list of Smart Grid standards to 16 “foundational standards” for Smart Grid.

Communication Protocols

Control Center to Control Center

- IEC 60870-6/TASE.2 – Inter-control Center Communications Protocol (ICCP)

Control Center to Field Equipment

- IEEE 1815 (DNP3) – North American Suppliers
- IEC 60870-5 – European Suppliers
  - 101 – serial communications
  - 103 – protection devices
  - 104 – TCP/IP (network communications)

Field Equipment

- IEC 61850 – substation automation and protection
- IEEE 1815 (DNP3) – substation and feeder device automation

New Sources of Data -
Unmanned Aerial Vehicles (UAVs) and Robotics

Data Characteristics

Data from a variety of sources

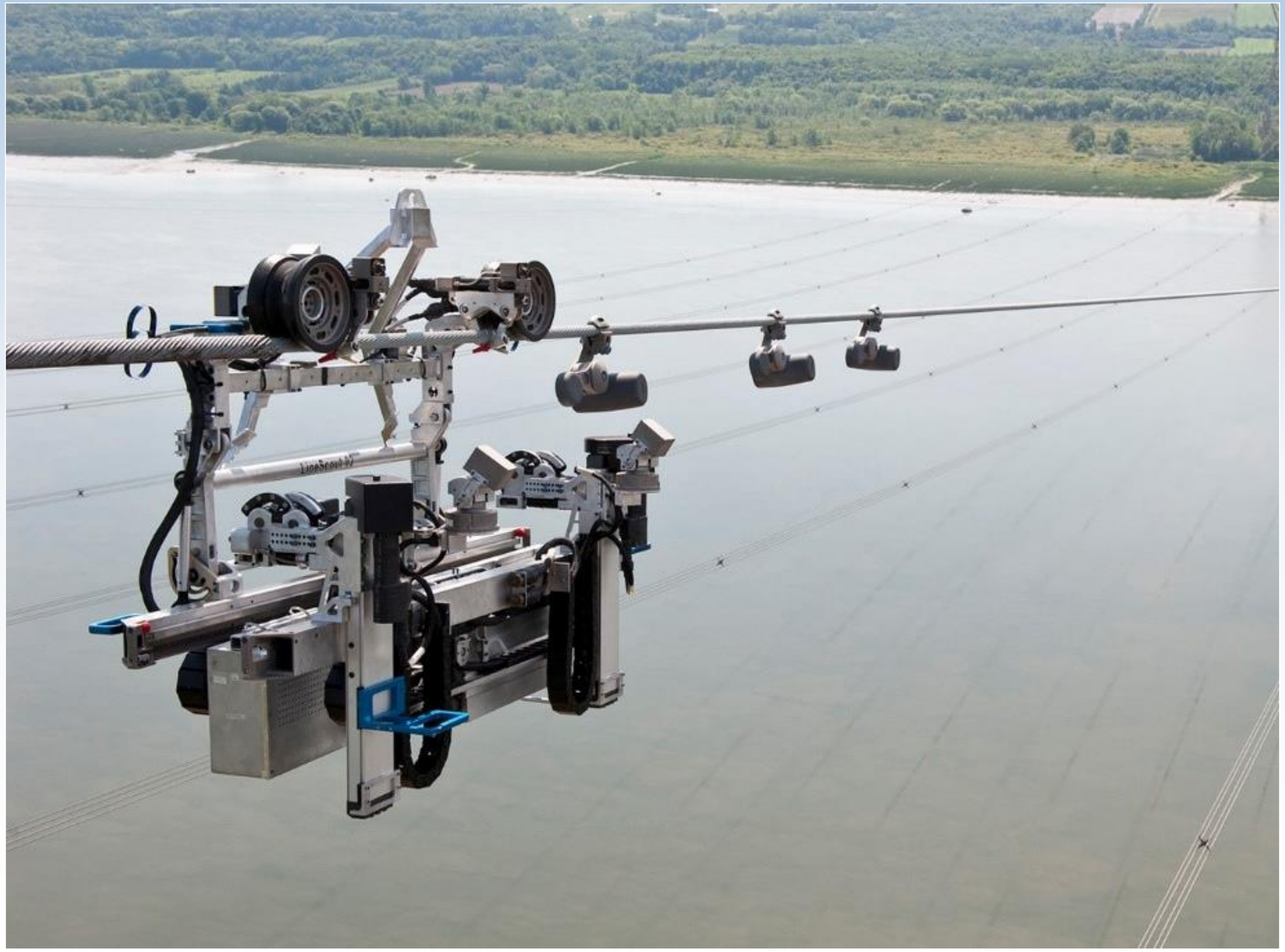
- Photography
- LiDar and PhoDar imagery
- Infrared sensors

Data used to inform

- Asset management program
- Geographic Information Systems (GIS)
- Outage Management Systems (OMS)
- Storm damage assessments

Data analysis

- Pursue automated image analysis to create value (having humans watching hours of streaming video is not practical or a beneficial use of resources)



Brief Ad Hoc Survey Conducted

Conducted brief ad hoc survey in late 2017

- Included utilities, consultants and power industry consortia
- Revealed how a coordinated industry response to the emergence of UAVs and robotics can speed time to value

Observations

- Power utility use of UAVs and robotics is in its infancy
- UAVs and robotics are an effective and efficient means to monitor infrastructure health and perform remedial work
- How raw and analyzed data is stored, routed or otherwise made available across a utility organization is <u>different</u> for each utility

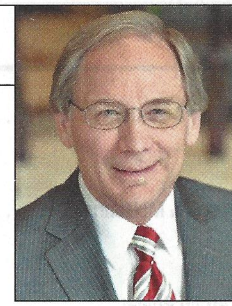
To Do Now

Recommendations

- “De-silo” the utility and its approach to data management to achieve the organization-wide value creation that creates a positive business case for new technologies and makes a power utility more nimble and competitive
- Now is the time to apply holistic data management thinking to how UAVs and robotics outputs are managed for value creation
- The power industry should determine and pursue common requirements for UAVs and robotics technologies and push UAV and robotic purveyors to comply with them
- Adopt standard data formats and data analytics based on open source architectures, and true enterprise-wide integration of the information
- Avoid proprietary solutions that limit the utility’s future options

Thank You!

Straight Talk



Drones and Robots:

A Data Management Opportunity

By **John D. McDonald**, GE Power's Grid Solutions business

Permit me the catchy headline, but let's clarify: this op-ed focuses on unmanned aerial vehicles (UAVs), unmanned aerial systems (UASs), robotics and related data management issues. UAVs are part of UASs, as the latter term reflects UAVs' reliance on ground-based pilots and a communications link (hence systems).

Currently, power utilities are exploring UAVs and robotics to determine their capabilities, use cases and business cases. UAVs appear to be effective in asset inspection and damage assessment, particularly for high-voltage transmission lines with ample rights-of-way. Robotics are a promising technology for live-line transmission system inspections and even underwater inspections of and repairs to hydroelectric dam turbines. Both devices and their data can inform asset management programs, outage management systems and geographic information systems, to name a few established benefits. Ultimately, UAVs and robotics are simply tools that achieve fundamental business goals: improved reliability, resiliency and customer satisfaction.

UAVs and robotics generate various types of nonoperational data, including imagery from video and still photography, LiDAR, PhoDAR, infrared and chemical sensors. Power utilities are experts at handling operational data, but still need to fully exploit nonoperational data from intelligent electronic devices and new sources such as UAVs and robotics. New nonoperational data sources need to be integrated into current utility systems as seamlessly as possible and made available to all authorized personnel who can create value from them.

"Holistic data management" refers to an approach that depends on collaboration between operations technology (OT) and information technology (IT) to create an information and communications technology (ICT) foundation that embraces open architectures and standards and ensures interoperability and backwards and forwards compatibility between devices, networks and databases. All operational and enterprise units must work together to map all sensors and other data sources to end users who can create value from that data. It includes a "data mart" that pushes out key data and resulting actionable intelligence or makes data available on-demand.

Holistic data management and its technology foundation will shorten time-to-value in the adoption of UAVs and robotics and help to build positive business cases for their use by widening the circle of end users who can create value from resulting data.

Without a comprehensive survey of the market, it isn't possible to characterize how many vendors are using open-source architectures and standards-based data protocols. But if the power utility industry's history is any guide, the market may well begin with a variety of proprietary solutions that fragment the market and slow the adoption curve.

In response, I'd suggest that the power industry as a whole should develop consensus on technologies, policies and standards for UAVs and robotics that provide vendors with clarity on meeting power industry requirements. This would avoid proprietary solutions that, as in the past, ultimately threaten to undercut investments, leave stranded assets and slow adoption of beneficial technologies.

I see room for optimism. Utilities are sharing their experiences in publications and conferences. The leading industry consortia — EPRI, EEI, IEEE societies, IEEE PES technical and coordinating committees — are assessing best practices, market offerings and automated image analysis, among other things. Efforts are afoot on supportive policies and standards.

UAVs and robotics are here now, and by adopting holistic data management strategies and the ICT foundation to support them, utilities will be prepared to exploit other new nonoperational data sources. If utilities act in concert to clarify industry requirements for vendors to ease adoption, they will be better prepared for the future. TDW

An Action Plan for UAVs/Robotics

- Build a strong grid with an ICT foundation built for future needs, before building a smart grid (requires IT/OT cooperation).
- Ensure ICT networks have the bandwidth, throughput and speed to handle all operational and nonoperational data for the foreseeable future.
- Pursue solutions, supported by technology, that align with business drivers and customer needs/expectations.
- Map data from sensor to potential end user and create a "data mart" that ensures every authorized person has access to all data that creates value (requires organization-wide collaboration).
- If/when UAVs and/or robotics prove useful to any given utility, that organization will have the ICT foundation and holistic data management practices in place to make full use of these new sources of data and improve the business case for them.
- The power industry should act in concert to demand that UAV and robotics vendors meet industry requirements with standard data formats and protocols to speed time to value.

John D. McDonald is a professional engineer, an IEEE Life Fellow, CIGRE U.S. National Committee vice president for technical activities, and smart grid business development leader for GE Power's Grid Solutions business.

Roadmap to the Future: Integrating Substation Information and Enterprise Level Applications

By: John McDonald, KEMA

By: Ali Ipakchi, KEMA

The past decade has seen a rapid advancement of technology supporting transmission and distribution utility engineering and operations. As such, the utility industry has increasingly turned to information and automation technology as a means to increase the efficiency of operations and to improve customer service.

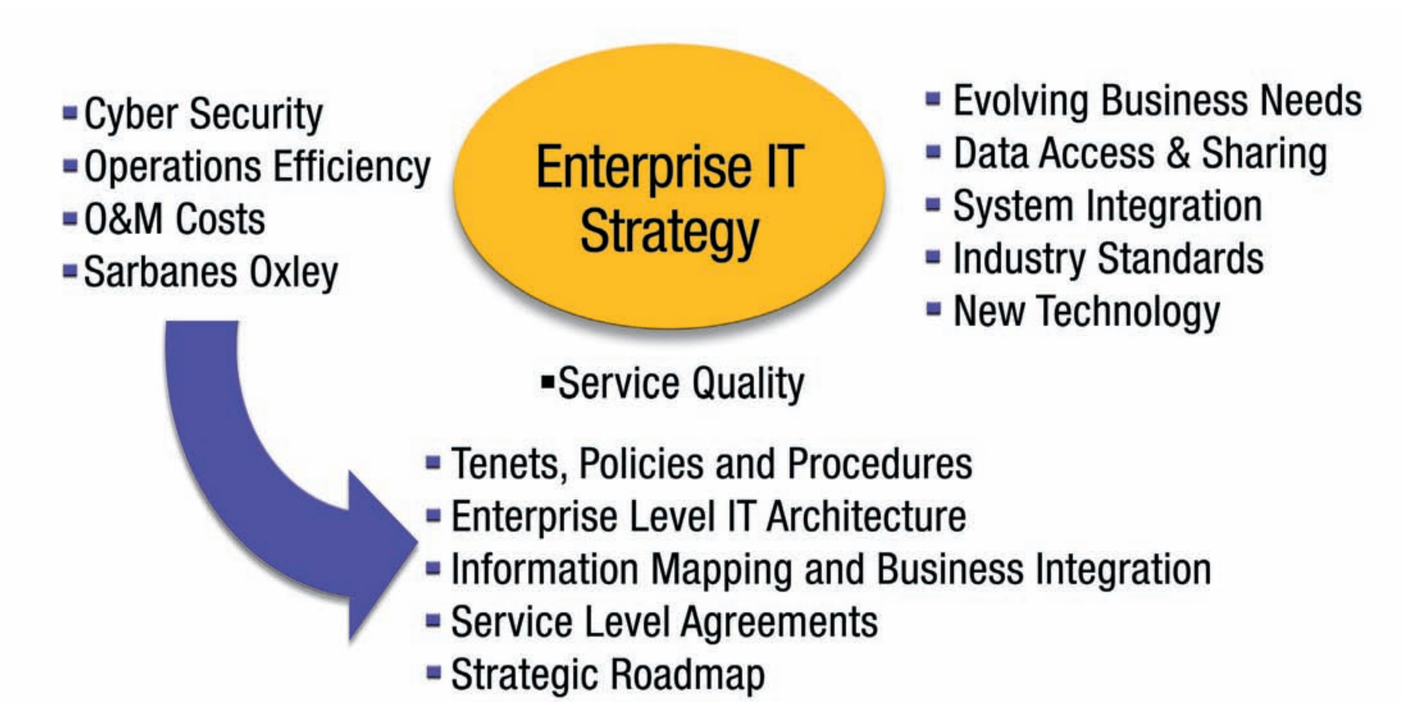
Traditionally, technology and automation projects are scoped, designed and deployed to support a given organizational unit. Often business function owners, faced with a specific business need, lead the procurement of a new application without enterprise level considerations for information integration and management, systems maintenance, and long-term support. The utility industry also faces the complexity of the real-time grid operations, system reliability, specialized mission critical applications and ever-changing regulatory environment and requirements. This is combined with more traditional IT paradigms of customer information, customer services, billing and back-office functions, asset management as well as administrative functions.

However, the industry has recognized that improved grid reliability, enhanced customer services, and improved operational efficiency will require information integration across the enterprise and enhanced levels of automation. User communities expect timely and often ubiquitous access to certain information, while management maintains pressure on costs, and higher levels of service quality and reliability. The emerging Utility of Future concepts for Smart Grid demand timely availability of additional information and integration of data and functions across traditional utility organizational boundaries. The improved access to information must be balanced with the appropriate levels of cyber security across the enterprise. And information management and control policies need to be in place to support access, reporting and audit requirements.

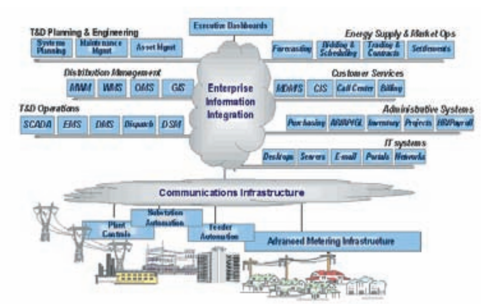
These challenges require utilities to establish tenets, policies and procedures for governing information assets and systems. To be effective, however, these tenets need to be driven by both requirements of IT systems management, as well as the realities of utility and grid operations and their specific business and technical requirements.

The technology

Traditionally, substation data were acquired through Remote Terminal Units (RTUs) and processed by Supervisory Control and Data Acquisition (SCADA) applications in support of power system operations. The introduction of multi-function digital relays and other Intelligent Electronic Devices (IEDs) at substations has made additional data available that can help minimize system restoration time, reduce equipment maintenance costs, and improve equipment availability and system reliability.



Modern substation protection and control systems use local-area networking technology to interconnect computer-based intelligent electronic devices that are able to communicate high-rate streams of electrical or other measurements (operational data) as well as records of how the devices and the power apparatus reacted to faults, system disturbances, and normal cycles of operation (non-operational data). This data is required to analyze the transient and long-term performance of the power system and its control systems. As compared to older non-intelligent systems that did not alert the utility of business opportunities or impending problems and disasters, the new systems provide vast quantities of valuable data.



Telemetry data, equipment conditions, digital fault recorder (DFR) and sequence of events (SOE) data can now be made available to users and applications in a consistent, and reliable fashion, using data marts and enterprise level integration schemes. This can facilitate the adaptation of performance enhancing strategies such as condition-based inspection and condition based maintenance (CBI/CBM) to improve equipment and system availability while reducing O&M costs. Continuous monitoring of dissolved gas levels, oil temperature, vibration levels, and HV transformer loading, for example, allows for the dynamic adjustment of equipment ratings to improve asset utilization and scheduling of inspection or maintenance. Timely access to, and analysis of, Digital Fault Recorder (DFR) and Sequence of Events (SOE) data allows quicker determination of fault location, and quicker service restoration.

Some utilities that integrated or automated substations hoping to get information for better management have found themselves wrestling with masses of data that overwhelm and handicap the organization. Realizing the strategic benefits of substation data is hindered by utility IT systems that frequently are not designed to allow access to this data by engineering and O&M applications. Comprehensive enterprise level substation systems integration (ELSSI) initiatives can help electric utilities get their arms around the huge bodies of data now stranded in substations. Converting masses of operational and non-operational data into business intelligence, organizing this intelligence, and interfacing it with enterprise-level applications can yield operating and financial benefits.

The key is to enable timely access to substation and equipment data by enterprise-wide users in planning, engineering, operations and maintenance that need this information. Utilities need to develop communications and processing systems that yield hard, timely, and succinct information for system operating security, economic operation, asset management, maintenance management, system planning, capital planning, and resource allocation. ELSSI adopters should understand key business metrics that support closed-loop business improvement processes. This makes it far easier to justify existing or new investments in substation automation and communications systems, and to reach the true payback promised by these substation systems.

Users also need to develop an approach that captures, organizes, and applies the data to assess improvements to system security and reliability, predict or schedule repair, replacement, or upgrading and the spending required, and to determine the most economical way to operate the system and the business. The challenge is to bridge the gap between the available substation data and the business goals. Utilities can bridge the gap by taking a number of interconnected steps including:

- Road-mapping solutions based on long-term utility business objectives;
- Planning communications system, data hosting, gathering, protection, and cyber security design;
- Organizing and interfacing data to applications that extract information;
- Selecting and developing applications that clearly and succinctly present all the enterprise users with the levels and types of information they need to perform their jobs; and
- Designing enterprise processes that close the loop between the management information delivered by ELSSI and the business improvements that result, constantly detecting and correcting problems, and constantly improving the whole cycle of information processing and use.

Roadmap for the future

Enterprise level systems integration is a complex process involving technology, applications, data, business process and people. Focusing on the road-mapping solutions step provides a high-level overview of general issues and approach for establishing a strategic plan for IT technology and systems integration across a utility enterprise.

A holistic view

Utility enterprise-wide systems integration and technology road mapping requires a holistic approach bringing together operational needs, business applications, data and process across the utility business units. This requires a broad range of subject matter expertise covering operating practices, technology requirements, and business opportunities across the organization. The technology roadmap should support business requirements and priorities, and provide a return on investment that can be supported both internally by the affected business units and externally through rate cases and regulatory process. This requires a multi-disciplinary approach to enable deep dives into specific technical and operational areas, when necessary, to ensure an effective strategy and deployment roadmap.

Utility IT professionals are increasingly faced with information integration needs across traditional organizational boundaries. However, many of the individual business improvement opportunities are difficult for utilities to justify on their individual merits, or to accomplish in the absence of readily available hard data. A holistic approach to providing integrated data enables the utilities to realize economic benefits in a similar holistic fashion that they could not approach taken piecemeal. However, this requires planning projects that cross the traditional organizational boundaries. Different business units may have to agree on the scope, budget and control of the technology. Utility IT professionals have become accustomed with enterprise applications, but in large part for applications outside of the operational environment. Enterprise level integration for support of operational systems will require a more careful planning and execution.

Beyond economic and operational benefits of systems integration, the need for better data management and controls is also becoming a driver for enterprise level strategies. Increasingly, information is viewed as an enterprise asset, which needs to be properly managed, controlled and made available to different enterprise users and applications. For example, Geographic Information Systems (GIS) data is needed by the Outage Management System (OMS) for outage management and restoration, used by Mobile...

...Workforce Management (MWM), needed by Customer Information System (CIS) for customer mapping, is used by systems planning and engineering in support of asset management and network analysis, is used by SCADA for world-maps, etc. Real-time equipment condition monitoring data is now being passed through SCADA to engineering and field crews for condition based inspection and maintenance activities, and used for asset management. Planning of information systems and enterprise applications require a holistic approach to address these diverse needs.

Typical components of utility enterprise information system assets include:

- T&D Planning and engineering - systems planning, maintenance management, asset management
- Distribution management – MWM, Work Management System (WMS), OMS, GIS
- T&D operations – SCADA, Energy Management System (EMS), Distribution Management System (DMS), dispatch, Demand Side Management (DSM)
- Energy supply and market operations - forecasting, bidding and scheduling, trading and contracts, settlements
- Customer service – Mobile Data Management System (MDMS), Customer Information System (CIS), call center, billing
- Administrative systems – purchasing, Accounts Receivable (AR)/Accounts Payable (AP)/General Ledger (GL), inventory, projects, Human Resources (HR)/payroll
- IT systems – desktops, servers, e-mail, portals, networks
- Communications infrastructure – plant controls, substation automation, feeder automation, advanced metering infrastructure

Enterprise wide integration brings these assets together, facilitating information access and sharing, utilization of common infrastructure and enabling applications and processes to achieve higher degrees of operational efficiency and reliability. This vision requires a strategic view to address an environment that may include many legacy applications, with no or limited integration capabilities, diverse data bases, data duplications and data quality issues, various standards and regulatory requirements, and diverse and evolving business needs.

Analysis approach

Planning, specification, design, deployment and maintenance of enterprise IT systems require significant levels of analysis and documentation that must follow a methodical approach. There are several technical approaches available, including Rational Unified Process (RUP) for technical analysis and requirements documentation, and well as KEMA's iAdvantageTM framework for project task activities, that can be tailored to specific utility requirements and operating culture. As appropriate, the supported industry standards, recommended technology stack, reference models and business practices, and tenets that will govern the information management, technology deployment and systems integration activities need to be identified.

In general, there are three broad areas of analysis and assessment to be considered:

Current state and requirements analysis - Current and the future state assessment activities should be based on the analysis of the various technology, data and process layers that encompass the solutions for an individual business application or the enterprise business needs. These layers include the infrastructure; the various vendor supplied or in-house developed business applications; the data, data access and its required security and controls; and the business processes and user functions.

Often, enterprise applications integration strategies and projects are based on the selection and deployment of information integration technologies, without much attention to the specific requirements and constraints of individual business applications and processes supporting those business functions. Technologies suitable for integration of transaction based applications, e.g., those typical in Customer Services, purchasing or administrative functions, may not be suitable for real-time and data intensive applications typical in T&D operations. The utility enterprise integration strategy needs to consider application area requirements and constraints.

Cost benefits assessment - Technology projects typically require cost and benefit justifications. Enterprise level projects impose an additional degree of complexity due to their broad reach and impact on multiple business activities. The analysis requires an understanding of business and operational benefits of the technology to often highly technical T&D and other operational facets of the business. The analysis may require assessment of strategies, options and alternatives. Deep subject matter expertise is often needed not only to perform the analysis but also to have the support and buy-in from the functional and business owners.

Qualitative and quantitative analysis should be performed based on business objectives, nature of the project and data availability. Where utility specific data is not readily available, utility industry best practices is used as a reference in assessing the benefit and cost magnitudes. The technology benefits, at a macro level, may be grouped into the following key categories: Increase Workforce Productivity; Improved Customer Services; Improve Electric Service Reliability, e.g., reduced outage frequency and duration; Increase System Operations Efficiency; Reduce/Defer/Eliminate Capital Investment. Automation and technology projects can thus be linked directly to business benefits and metrics, as an integral part of the enterprise strategy.

Cost benefit models become an effective tool for evaluation of alternative strategies and their sensitivity to schedule, capital and O&M cost variations. Advanced analysis techniques, e.g., Real Options analysis, may be deployed for support of multi-year phased projects.

Technical approach - The enterprise technology and integration strategy also requires establishing reference models for recommended technology stack and integration framework. Most utilities already have adopted a recommended position for enterprise technology stack. However, these are not fully applied as guidelines to systems and applications supporting engineering and operations. Integration reference model complements the technology stack and established recommendations for services, standards, design components, and patterns that are used in design, implementation and enhancements of integration infrastructure. Applicable industry standards and practices, e.g., Common Information Model (CIM), various Service Oriented Architecture (SOA) requirements, NERC cyber security for critical infrastructure (CIP), and other applicable standards may be considered. Systems integration requires numerous interactions internally and externally, and these interactions are typically implemented via SOA or, in other words, by consuming or providing services. ■

About the Authors

John D. McDonald, P.E., *is Vice President, Automation for KEMA, Inc., with 32 years of experience in the electric utility industry. John is currently assisting electric utilities in substation automation, distribution SCADA, communication protocols and SCADA/DMS.*

Dr. Ali Ipakchi *is Vice President, Integration Services for KEMA Inc. with over 27 years of experience in delivering system solutions and services to the electric utility industry, he has managed large technical teams for leading vendors, and offers a successful track record of developing new products and services, as well as business and organizational infrastructure to address emerging market requirements.*

John D. McDonald

substation automation

IED integration and availability of information

ELECTRIC UTILITY DEREGULATION, economic pressures forcing downsizing, and the marketplace pressures of potential takeovers have forced utilities to examine their operational and organizational practices. Utilities are realizing that they must shift their focus to customer service. Customer service requirements all point to one key element: information, i.e., the right amount of information to the right person or computer within the right amount of time. The flow of information requires data communication over extended networks of systems and users. In fact, utilities are becoming among the largest users of data and are the largest users of real-time information.

The advent of industry deregulation has placed greater emphasis on the availability of information, the analysis of this information, and the subsequent decision-making to optimize system operation in a competitive environment. Intelligent electronic devices (IEDs) being implemented in substations today contain valuable information, both operational and nonoperational, needed by many user groups within the utility. The challenge facing utilities is determining a standard integration architecture that meets the utility's specific needs, can extract the desired operational and nonoperational information, and deliver this information to the users who have applications to analyze the information.

This issue of *IEEE Power & Energy Magazine* focuses on substation integration and automation. My Guest Editorial provides an overview of substation integration and automation fundamentals and focuses on best practices. It also includes a list of:

- further reading material for those who require more information on the same subject
- acronyms and abbreviations for those readers who are not familiar with the terminology.

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Three feature articles follow with more specific information on:

- a business case methodology for expanding the implementa-

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tion of substation automation technologies at MidAmerican Energy Company
- ✔ a pilot project at Omaha Public Power District to integrate data from various devices within two substations and a simulator
- ✔ a generic architecture that applies the multiagent systems methodology to the field of substation automation.

Open Systems

An open system is a computer system that embodies supplier-independent standards so that software may be applied on many different platforms and can interoperate with other applications on local and remote systems. An open system is an evolutionary means for a substation control system that is based on the use of nonproprietary, standard software and hardware interfaces. Open systems enable future upgrades available from multiple suppliers at lower cost to be integrated with relative ease and low risk.

The concept of open systems applies to substation automation. It is important to learn about the different de jure (legal) and de facto (actual) standards and then apply them so as to eliminate proprietary approaches. An open systems approach allows the incremental upgrade of the automation system without the need for complete replacement, as happened in the past with proprietary systems. There is no longer the need to rely on one supplier for complete implementation. Systems and IEDs from competing suppliers are able to interchange and share information. The benefits of open systems include longer expected system life, investment protection, upgradeability and expandability, and readily available third-party components.

Levels of Integration and Automation

Substation integration and automation can be broken down into five levels, as shown in Figure 1. The lowest level is the power system equipment, such as transformers and circuit breakers. The middle three levels are IED implementation, IED integration, and substation automation applications. All electric utilities are implementing IEDs in their substations. The focus today is on the integration of the IEDs. Once this is done, the focus will shift to what automation applications should run at the substation level. The highest level is the utility enterprise, and there are multiple functional data paths from the substation to the utility enterprise.

Utility Enterprise
Substation Automation Applications
IED Integration
IED Implementation
Power System Equipment (Transformers, Breakers)

figure 1. Five levels of substation integration and automation.

Since substation integration and automation technology is fairly new, there are no industry standard definitions, except for the definition of an IED. The industry standard definition of an IED is given below, as well as definitions for substation integration and substation automation.

- ✔ *IED*: Any device incorporating one or more processors with the capability to receive or send data/control from or to an external source (e.g., electronic multifunction meters, digital relays, controllers). An example of a relay IED is shown in Figure 2.
- ✔ *Substation integration*: Integration of protection, control, and data acquisition functions into a minimal number of platforms to reduce capital and operating costs, reduce panel and control room space, and eliminate redundant equipment and databases.
- ✔ *Substation automation*: Deployment of substation and feeder operating functions and applications ranging from supervisory control and data acquisition (SCADA) and alarm processing to integrated volt/var control in order to optimize the management of capital assets and enhance operation and maintenance (O&M) efficiencies with minimal human intervention.

figure 2. Example of a relay IED.

Architecture Functional Data Paths

There are three primary functional data paths from the substation to the utility enterprise, as shown in Figure 3. The most common data path is conveying the operational data (e.g., volts, amps) to the utility's SCADA system every 2 to 4 s. This information is critical for the utility's dispatchers to monitor and control the power system. The most challenging data path is conveying the nonoperational data to the utility's data warehouse. The challenges associated with this data path include the characteristics of the data (waveforms rather than points), the periodicity of data transfer (not continuous, on demand), and the protocols used to obtain the data from the IEDs (not standard, IED supplier's proprietary protocols). Another challenge is whether the data

> A corporate data warehouse enables users to access substation data while maintaining a firewall to substation control and operation functions.

is pushed from the substation into the data warehouse, pulled from the data warehouse, or both. The third data path is remote access to an IED by passing through or looping through the substation integration architecture and isolating a particular IED in the substation.

Data Warehouse

The corporate data warehouse enables users to access substation data while maintaining a firewall to substation control and operation functions. Both operational and nonoperational data is needed in the data warehouse. To size the data warehouse, the utility must determine who the users of the substation automation system data are, the nature of their application, the type of data needed, how often the data is needed, and the frequency of update required for each user. Examples of user groups within a utility are substation design engineering, protective relay engineering, protective relay technicians, substation metering, substation operations, control center operations, engineering planning, transmission and distribution engineering, power quality, substation test, substation maintenance, predictive maintenance, communications engineering, SCADA, feeder automation, and information technology.

SA System Functional Architecture Diagram

The functional architecture diagram in Figure 4 shows the three functional data paths from the substation to the utility enterprise, as well as the SCADA system and the data warehouse. The operational data path to the SCADA system utilizes the communication protocol presently supported by the SCADA system. The nonoperational data path to the data warehouse conveys the IED nonoperational data from the SA system to the data warehouse, either being pulled by a data warehouse application from the SA system or being pushed from the SA system to the data warehouse based on an event trigger or time. The remote access path to the substation utilizes a dial-in telephone connection. The global positioning system (GPS) satellite clock time reference is shown, providing a time reference for the SA system and IEDs in the substation. The PC provides the graphical user interface (GUI) and the historical information system for archiving operational and nonoperational data. The SCADA interface knows which SA system points are sent to the SCADA system, as well as the SCADA system protocol. The local area network (LAN) enabled IEDs can be directly connected to the SA LAN. The non-LAN enabled IEDs require a network interface module (NIM) for protocol and physical interface conversion. The IEDs can have various applications, such as equipment condition monitoring (ECM) and relaying, as well as direct (or hardwired) input/output (I/O).

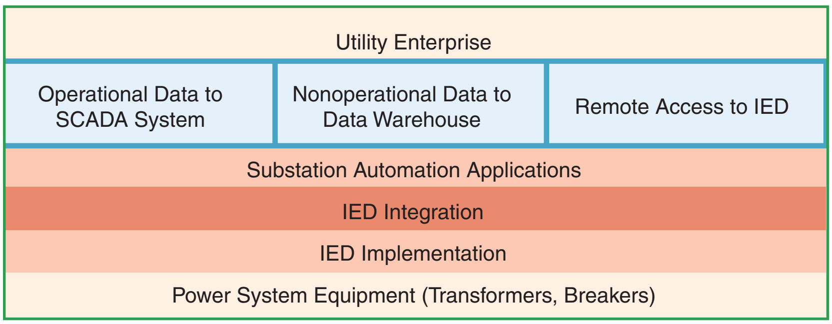

figure 3. Three functional data paths from substation to utility enterprise.

New Versus Existing Substations

The design of new substations has the advantage of starting with a blank sheet of paper. The new substation will typically have many IEDs for different functions, and the majority of operational data for the SCADA system will come from these IEDs. The IEDs will be integrated with digital two-way communications. The small amount of direct input/output (hardwired) can be acquired using programmable logic controllers (PLCs). Typically, there are no conventional remote terminal units (RTUs) in new substations. The RTU functionality is addressed using IEDs, PLCs, and an integration network using digital communications.

In existing substations, there are several alternative approaches, depending on whether or not the substation has a conventional RTU installed. The utility has three choices for their existing conventional substation RTUs:

- ✔ Integrate RTU with IEDs: Many utilities have integrated IEDs with existing conventional RTUs, provided the RTUs support communications with downstream devices and support IED communication protocols. This integration approach works well for the operational data path but does not support the nonoperational and remote-access data paths. The latter two data paths must be done outside of the conventional RTU.
- ✔ Integrate RTU as another substation IED: If the utility desires to keep its conventional RTU, the preferred approach is to integrate the RTU in the substation integration architecture as another IED. In this way, the RTU can be retired easily as the RTU hardwired direct input/output transitions to come primarily from the IEDs.

- ✔ Retire RTU and use IEDs and PLCs as with a new substation: The RTUs may be old and difficult to support, and the substation automation project may be a good time to retire these older RTUs. The hardwired direct input/output from these RTUs would then come from the IEDs and PLCs as with a new substation.

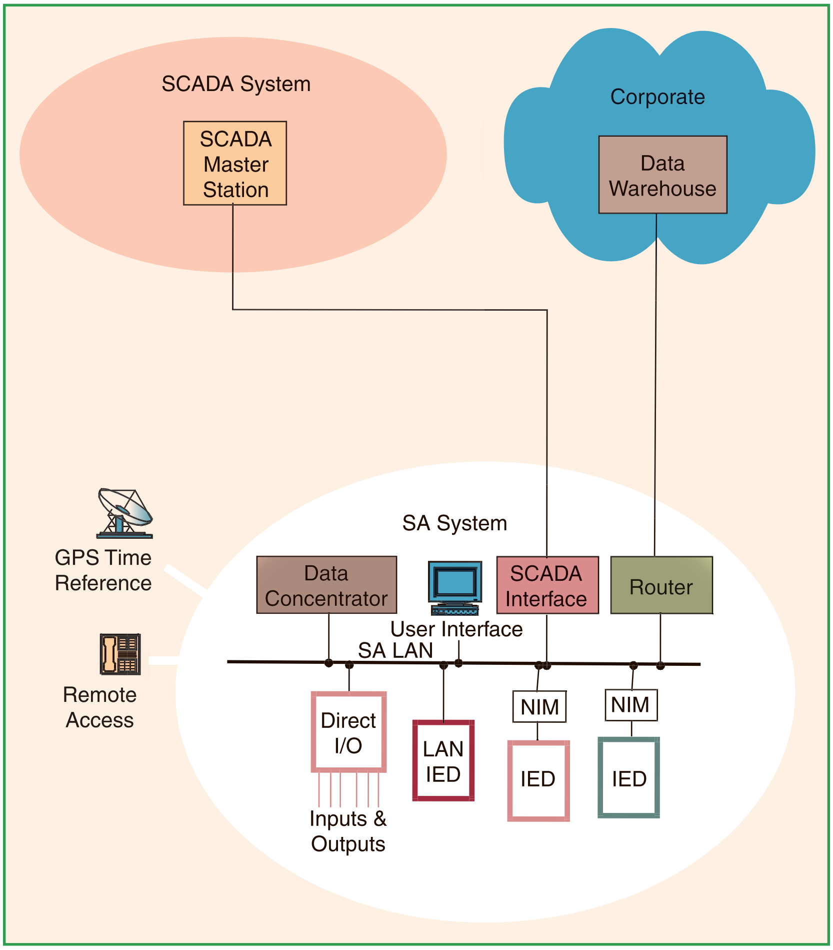

figure 4. SA system functional architecture diagram.

Equipment Condition Monitoring

Many electric utilities have employed ECM to maintain electric equipment in top operating condition while minimizing the number of interruptions. With ECM, equipment-operating parameters are automatically tracked to detect the emergence of various abnormal operating conditions. This allows substation operations personnel to take timely action when needed to improve reliability and extend equipment life. This approach is applied most frequently to substation transformers and high voltage electric supply circuit breakers to minimize the maintenance costs of these devices, as well as improve their availability and extend their useful life. Figure 5 shows an ECM IED installed on a substation transformer.

Equipment availability and reliability may be improved by reducing the amount of offline maintenance and testing required, as well as reducing the number of equipment failures. To be truly effective, equipment condition monitoring should be part of an overall condition-based maintenance strategy that is properly designed and integrated into the regular maintenance program.

ECM IEDs are being implemented by many utilities. In most implementations, the communication link to the IED is via a dial-up telephone line. To facilitate integrating these IEDs into the substation architecture, the ECM IEDs must support at least one of today's widely used IED protocols: Modbus, Modbus Plus, or Distributed Network Protocol version 3 (DNP3). In addition, a migration path to utility communications architecture version 2 (UCA2) manufacturing message specification (MMS) protocol is desired. If the ECM IEDs can be integrated into the substation architecture, the operational data will have a path to the SCADA system, and the nonoperational data will have a path to the utility's data warehouse. In this way, the users and systems throughout the utility that need this information will have access to it. Once the information is brought out of the substation and into the SCADA system and data warehouse, users can share the information in the utility. The "private" databases that result in islands of automation will go away. Therefore, the goal of every utility is to integrate these ECM IEDs into a standard substation integration architecture so that both operational and nonoperational information from the IEDs can be shared by utility users.

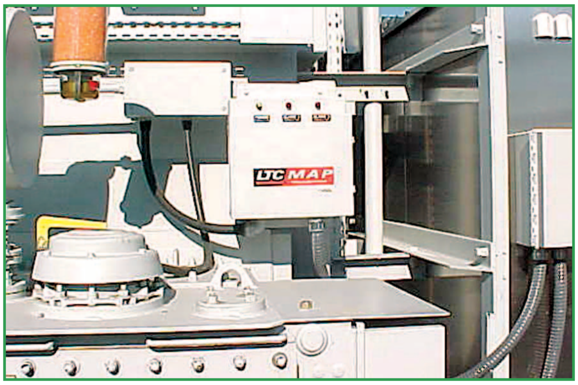

figure 5. ECM IED installed on substation transformer.

Substation Automation Training Simulator

One of the challenges for electric utilities when implementing substation automation for the first time is to create

figure 6. Substation automation training simulator.

"buy-in" for the new technology within the utility. The more people know about a subject the more comfortable they feel and the better the chance they will use the technology. It is much easier and less stressful to learn about substation automation technology in a training environment, away from the substation, than on a system installed in an energized substation. For these reasons, many utilities purchase a substation automation training simulator (SATS), which is an identical configuration to that installed in substations. The main difference is that the SATS includes at least one of every kind of IED installed in all substations. In addition to training, SATS is used for application development and testing of new IEDs. An example of a SATS presently installed at an electric utility is shown in Figure 6.

Protocol Fundamentals

A communication protocol allows communication between two devices. The devices must have the same protocol (and version) implemented. Any protocol differences will result in communication errors.

If the communication devices and protocols are from the same supplier, i.e., where a supplier has developed a unique protocol to utilize all the capabilities of the two devices, it is unlikely the devices will have trouble communicating. By using a unique protocol of one supplier, a utility can maximize the device's functionality and see a greater return on its investment; however, the unique protocol will constrain the utility to one supplier for support and purchase of future devices.

If the communication devices are from the same supplier but the protocol is an industry-standard protocol supported by the device supplier, the devices should not have trouble communicating. The device supplier has designed its devices to operate with the standard protocol and communicate with other devices using the same protocol and version. By using a standard protocol, the utility may purchase equipment from any supplier that supports the protocol and, therefore, can comparison-shop for the best prices.

Industry-standard protocols typically require more overhead than a supplier's unique protocol. Standard protocols often require a higher speed channel than a supplier's unique protocol for the same efficiency or information throughput. However, high-speed communication channels are more prevalent today and may provide adequate efficiency when using industry-standard protocols. UCA2 MMS is designed to operate efficiently over 10 Mb/s switched or 100 Mb/s shared or switched Ethernet. If a utility is considering UCA2 MMS as its protocol of choice, a prerequisite should be installation of high-speed communications. If the utility's plan is to continue with a communication infrastructure operating at 1,200 to 9,600 b/s, the better choice for an industry-standard protocol would be DNP3.

A utility may not be able to utilize all of a device's functionality using an industry standard protocol. If a device was designed before the industry standard protocol, the protocol may not thoroughly support the device's functionality. If the device was designed after the industry standard protocol was developed, the device should have been designed to work with the standard protocol such that all of the device's functionality is available.

The substation integration and automation architecture must allow devices from different suppliers to communicate (interoperate) using an industry-standard protocol. The utility has the flexibility to choose the best devices for each application, provided the suppliers have designed their devices to achieve full functionality with the protocol. Though devices from different suppliers can operate and communicate under the standard protocol, each device may have capabilities not supported by the other device. There is also a risk that the protocol implementations of the industry-standard protocol by the two suppliers in each device may have differences. Factory testing will verify that the functions of one device are supported by the protocol of the other device and vice versa. If differences and/or incompatibilities are found, they can be corrected during factory testing.

Protocol Considerations

There are two capabilities a utility considers for an IED. The primary capability of an IED is its standalone capabilities, such as protecting the power system for a relay IED. The secondary capability of an IED is its integration capabilities, such as its physical interface (e.g., RS-232, RS-485, Ethernet) and its communication protocol (e.g., DNP3, Modbus, UCA2 MMS).

Today utilities typically specify the IEDs they want to use in the substation rather than giving a supplier a turnkey contract to provide the supplier's IEDs only in the substation. However, utilities typically choose the IEDs based on the IED's standalone capabilities only, without considering the IED's integration capabilities. Once the IEDs are installed, the utility may find in the future, when they want to integrate the IEDs, that the IEDs were purchased with the IED supplier's proprietary protocol and with a physical interface not desired (RS-485 purchased when Ethernet is desired). When purchasing IEDs, the utility must consider both the standalone capabilities in the choice of the IED and the integration capabilities when ordering the IED, even if the IEDs will not be integrated in the near future.

Today, the most common IED communication protocols are Modbus, Modbus Plus, and DNP3. The UCA2 MMS protocol is becoming commercially available from more IED suppliers and being implemented in more utility substations. However, the implementations may not be optimal (adding a separate box for the UCA2 MMS protocol and Ethernet networking) and may result in poor performance (data latency due to the additional box) rather than the supplier incorporating the new functionality into the existing IED. The utility must be cautious when ordering an IED with other than the IED supplier's target protocol, often supplier proprietary, used in the design of the IED. Some IED functionality may be lost when choosing other than the IED supplier's target protocol.

The most common IED networking technology today in substations is serial communications, either RS-232 or RS-485. As more and more IEDs become available with Ethernet ports, the IED networking technology in the substation will be primarily Ethernet.

Utility Communication Architecture

The use of international protocol standards is now recognized throughout the electric utility industry as a key to successful integration of the various parts of the electric utility enterprise. One area addresses substation integration and automation protocol standardization efforts. These efforts have taken place within the framework provided by the Electric Power Research Institute's (EPRI's) UCA.

UCA is a standards-based approach to utility data communications that provides for wide-scale integration from the utility enterprise level (as well as between utilities) down to the customer interface, including distribution, transmission, power plant, control center, and corporate information systems. UCA version 1.0 specification was issued in December 1991 as part of EPRI Project RP2949, Integration of Utility Communication Systems. While this specification supplied a great deal of functionality, industry adoption was limited, due in part to a lack of detailed specifications about how the specified protocols would actually be used by applications. For example, the MMS (ISO/IEC 9506) protocol was specified for real-time data exchange at many levels within a utility, but specific mappings to MMS for exchanging power

Acronyms and Abbreviations

DNP	distributed network protocol
ECM	equipment condition monitoring
EPRI	Electric Power Research Institute
GOMSFE	generic object models for substation and feeder equipment
GPS	global positioning system
ICCP	inter-control center communications protocol
IEC	International Electrotechnical Commission
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers, Inc.
I/O	input/output
ISO	International Standards Organization
IT	information technology
LAN	local area network
Mb/s	megabits per second
MMS	manufacturing messaging specification
NIM	network interface module
O&M	operations and maintenance
PES	IEEE Power Engineering Society
PLC	programmable logic controller
PSRC	IEEE PES Power Systems Relaying Committee
RF	radio frequency
RFP	request for proposal
RTU	remote terminal unit
SA	substation automation
SATS	substation automation training simulator
SCADA	supervisory control and data acquisition
TC	technical committee
TCP/IP	transmission control protocol and Internet protocol
UCA	utility communication architecture
var	volt ampere reactive
WAN	wide area network
WG	working group

Benefits of open systems include longer expected system life, investment protection, upgradeability and expandability, and readily available third-party components.

system data and schedules or for communicating directly with substation or distribution feeder devices was lacking, resulting in continuing interoperability problems.

The UCA (MMS) Forum was started in May 1992 to address these UCA application issues. Six working groups were established to consider issues of MMS application in power plants, control centers, customer interface, substation automation, distribution feeder automation, and profile issues. The MMS Forum served as a mechanism for utilities and suppliers to build the technical agreements necessary to achieve a wide range of interoperability using UCA MMS. Out of these efforts came the notion of defining standard power system objects and mapping them onto the services and data types supported by MMS and the other underlying standard protocols. This heavily influenced the definition of the UCA2 specification issued in late 1996, which endorses ten different protocol profiles, including transmission control protocol and Internet protocol (TCP/IP) and inter-control center communications protocol (ICCP), as well as a new set of common application service models for real-time device access.

The EPRI UCA Substation Automation Project began in the early 1990s to produce industry consensus regarding substation integrated control, protection, and data acquisition and to allow interoperability of substation devices from different manufacturers. The Substation Protocol Reference Specification recommended three of the ten UCA2 profiles for use in substation automation. Future efforts in this project were integrated with the efforts in the Utility Substations Initiative.

In mid-1996, American Electric Power hosted the first Utility Substations Initiative meeting, as a continuation of the EPRI UCA Substation Automation Project. Approximately 40 utilities and 25 suppliers are presently participating, having formed supplier/utility teams to define the supplier IED functionality and to implement a standard IED protocol (UCA2 profile) and LAN protocol (Ethernet).

Generic object models for substation and feeder equipment (GOMSFE) are being developed to facilitate suppliers in implementing the UCA Substation Automation Project substation and feeder elements of the power system object model. New IED products with this functionality are now commercially available. The Utility Substations Initiative meets three times each year, in January, May, and September, immediately following the IEEE PES Power System Relaying Committee (PSRC) meetings and in conjunction with the UCA Users Group meetings. Every other meeting includes a supplier interoperability demonstration. The demonstration in September 2002 involved approximately 20 suppliers with products interconnected by a fiber Ethernet LAN interoperating with the UCA2 MMS protocol, the GOMSFE device object models, and Ethernet networks.

The UCA Users Group is a nonprofit organization whose members are utilities, suppliers, and users of communications for utility automation. The mission of the UCA Users Group is to enable utility integration through the deployment of open standards by providing a forum in which the various stakeholders in the utility industry can work cooperatively together as members of a common organization to:

- ✔ influence, select, and/or endorse open and public standards appropriate to the utility market based on the needs of the membership
- ✔ specify, develop, and/or accredit product/system-testing programs that facilitate the field interoperability of products and systems based upon these standards
- ✔ implement educational and promotional activities that increase awareness and deployment of these standards in the utility industry.

The UCA Users Group was first formed in 2001 and presently has 34 corporate members, including 17 suppliers, 14 electric utilities, and three consultants and other organizations. The UCA Users Group organization consists of a Board of Directors, with the Executive Committee and Technical Committee reporting to the board. The Executive Committee has three committees reporting to it: Marketing, Liaison, and Membership. The Technical Committee has a number of committees reporting to it, including Substation, Communications, Products, Object Models (IEC 61850/GOMSFE), and Test Procedures. The Web site for the UCA Users Group is www.ucausersgroup.org. The group meets three times each year, in January, May and September, immediately following the IEEE PES PSRC meetings and in conjunction with the Utility Substations Initiative meetings. In addition, the UCA Users Group will meet at the IEEE PES Substations Committee Annual Meeting 27-30 April 2003 in Sun Valley, Idaho. This meeting will include a supplier interoperability demonstration with 20 to 25 suppliers demonstrating the implementation of the UCA2 MMS protocol and Ethernet networking technology into their IEDs and products and interoperating with the other suppliers' equipment.

IEC 61850

The UCA2 substation automation work has been brought to IEC Technical Committee (TC) 57 Working Groups

(WGs) 10, 11, and 12, who are developing IEC 61850, the single worldwide standard for substation automation communications. IEC 61850 is based on UCA2 and European experience and provides additional functions such as substation configuration language and a digital interface to nonconventional current and potential transformers.

Distributed Network Protocol

The development of DNP was a comprehensive effort to achieve open, standards-based interoperability between substation computers, RTUs, IEDs, and master stations (except inter-master-station communications) for the electric utility industry. DNP is based on the standards of the IEC TC 57, WG 03. DNP has been designed to be as close to compliant as possible to the standards as they existed at the time of development with the addition of functionality not identified in Europe but needed for current and future North American applications (e.g., limited transport layer functions to support 2K block transfers for IEDs, radio frequency (RF), and fiber support). The present version of DNP is DNP3, which is defined in three distinct levels. Level 1 has the least functionality, for simple IEDs, and Level 3 has the most functionality, for SCADA master-station communication front-end processors.

The short-term benefits of using DNP are:

- ✔ interoperability between multi-supplier devices
- ✔ fewer protocols to support in the field
- ✔ reduced software costs
- ✔ no protocol translators needed
- ✔ shorter delivery schedules
- ✔ less testing, maintenance, and training
- ✔ improved documentation
- ✔ independent conformance testing
- ✔ support by independent user group and third-party sources (e.g., test sets, source code).

In the long term, further benefits can be derived from using DNP, including:

- ✔ easy system expansion
- ✔ long product life
- ✔ more value-added products from suppliers
- ✔ faster adoption of new technology
- ✔ major operations savings.

DNP was developed by Harris, Distributed Automation Products, in Calgary, Alberta, Canada. In November 1993, responsibility for defining further DNP specifications and ownership of the DNP specifications was turned over to the DNP User Group, a group composed of utilities and suppliers who are utilizing the protocol. The DNP User Group is a forum of over 300 users and implementers of the DNP3 protocol worldwide. The major objectives of the group are to:

- ✔ maintain control of the protocol and determine the direction in which the protocol will migrate
- ✔ review and add new features, functions, and enhancements to the protocol
- ✔ encourage suppliers and utilities to adopt the DNP3 protocol as a standard
- ✔ define recommended protocol subsets
- ✔ develop test procedures and verification programs
- ✔ support implementer interaction and information exchange.

The DNP User Group has an annual general meeting in North America, usually in conjunction with the DistribuTECH Conference in February/March. The Web site for DNP and the DNP User Group is www.dnp.org. The DNP User Group Technical Committee is an open volunteer organization of industry and technical experts from around the world. This committee evaluates suggested modifications or additions to the protocol and then amends the protocol description as directed by the User Group members.

Choosing the Right Protocol

There are several factors to consider when choosing the right protocol for your application. First, determine the system area with which you are most concerned, e.g., the protocol from a SCADA master station to the SCADA RTUs, a protocol from substation IEDs to an RTU or a PLC, or a LAN in the substation. Second, determine the timing of your installation, e.g., six months, 18 to 24 months, or three to five years. In some application areas, technology is changing so quickly that the timing of your installation can have a great impact on your protocol choice. If you are implementing new IEDs in the substation and need them to be in service in six months, you could narrow your protocol choices to DNP3, Modbus, and Modbus Plus. These protocols are used extensively in IEDs today. If you choose an IED that is commercially available with UCA2 MMS capability today, then you may choose UCA2 MMS as your protocol.

If your timeframe is one to two years, you should consider IC 61850 and UCA2 MMS as the protocol. Monitor the results of the Utility Substation Communication Initiative utility demonstration sites. These sites have implemented new supplier IED products that are using UCA2 MMS as the IED communication protocol and Ethernet as the substation local area network.

If your timeframe is near term (six to nine months), make protocol choices from suppliers who are participating in the industry initiatives and are incorporating this technology into their product's migration paths. This will help protect your investment from becoming obsolete by allowing incremental upgrades to new technologies.

Communication Protocol Application Areas

There are various protocol choices depending on the protocol application area of your system. Protocol choices vary with the different application areas. Different application areas are in different stages of protocol development and industry efforts. The status of development efforts for different applications will help determine realistic plans and schedules for your specific projects.

> Selecting the right supplier ensures that you stay informed about industry developments and trends and allows you to access new technologies with the least impact on your current operation.

Within the Substation

The need for a standard IED protocol dates back to the late 1980s. IED suppliers acknowledge that their expertise is in the IED itself, not in two-way communications capability, the communications protocol, or added IED functionality from a remote user. Though the industry made some effort to add communications capability to the IEDs, each IED supplier was concerned that any increased functionality would compromise performance and drive the IED cost so high that no utility would buy it. Therefore, the industry vowed to keep costs competitive and performance high as standardization was incorporated into the IED.

The IED supplier's lack of experience in two-way communications and communication protocols resulted in crude, primitive protocols and, in some cases, no individual addressability and improper error checking (no select-before-operate). Each IED required its own communication channel, but only limited channels, if any, were available from RTUs. SCADA system and RTU suppliers were pressured to develop the capability to communicate to IEDs purchased by the utilities. Each RTU and IED interface required not only a new protocol but a proprietary protocol not used by any other IED.

It was at this point that the Data Acquisition, Processing and Control Systems Subcommittee of the IEEE Power Engineering Society (PES) Substations Committee recognized the need for a standard IED protocol. The subcommittee formed a task force to examine existing protocols and determine, based on two sets of screening criteria, the two best candidates. *Trial Use Recommended Practice for Data Communications Between Intelligent Electronic Devices and Remote Terminal Units in a Substation* (IEEE Standard 1379) was published in March 1998. This document did not establish a new communication protocol. To quickly achieve industry acceptance and use, it instead provided a specific implementation of two existing communication protocols in the public domain, DNP3 and IEC 870-5-101.

For IED communications, if your implementation timeframe is six to nine months, select from protocols that already exist: DNP3, Modbus, and Modbus Plus. However, if the implementation timeframe is one year or more, consider UCA2 MMS as the communications protocol. Regardless of your timeframe, evaluate each supplier's product migration plans. Try to determine if the system will allow migration from today's IED with DNP3 to tomorrow's IED with UCA2 MMS without replacing the entire IED. This will leave open the option of migrating the IEDs in the substation to UCA2 in an incremental manner, without wholesale replacement. If you choose an IED that is commercially available with UCA2 MMS capability today, then you may want to choose UCA2 MMS as your IED protocol.

Substation to Utility Enterprise

This is the area of traditional SCADA communication protocols. The Data Acquisition, Processing, and Control Systems Subcommittee of the IEEE PES Substations Committee began developing a recommended practice in the early 1980s in an attempt to standardize master/remote communications practices. At that time, each SCADA system supplier had developed a proprietary protocol based on technology of the time. These proprietary protocols exhibited varied message structures, terminal-to-data circuit terminating equipment (DCE) and DCE-to-channel interfaces, and error detection and recovery schemes. The *IEEE Recommended Practice for Master/Remote Supervisory Control and Data Acquisition (SCADA) Communications* (IEEE Standard 999-1992) addressed this nonuniformity among the protocols, provided definitions and terminology for protocols, and simplified the interfacing of more than one supplier's RTUs to a master station.

The major standardization effort undertaken in this application area has taken place in Europe as part of the IEC standards-making process. The effort resulted in the development of the IEC 870-5 protocol, which was slightly modified by GE (Canada) to create DNP. This protocol incorporated a pseudo transport layer, allowing it to support multiple master stations. The goal of DNP was to define a generic standards-based (IEC 870-5) protocol for use between IEDs and data concentrators within the substation, as well as between the substation and the SCADA system control center. Success led to the creation of the supplier-sponsored DNP User Group that currently maintains full control over the protocol and its future direction. DNP3 has become a de facto standard in the electric power industry and is widely supported by suppliers of test tools, protocol libraries, and services.

Cyber Security

When today's control systems were designed, information and system security was not a priority. SCADA and other control systems were designed as proprietary, stand-alone systems, and their security resulted from their physical and logical isolation and controlled access to them. As information technology becomes increasingly advanced, substation automation continues to move to open, standards-based networking technologies and/or the Internet to bring the benefits of information sharing to operations. All suppliers have the capability to implement Web-based applications to perform monitoring, control, and remote diagnostics. This, however, leads to control system cyber vulnerabilities. Existing information technology (IT) can protect substation control systems from traditional IT vulnerabilities, but they are not designed to protect control systems against vulnerabilities unique to control systems.

A security policy and a mechanism for its enforcement should be developed for the substation. A minimum list of questions to be addressed before attaching the SA system (or SCADA system) to the network include the following.

- ✔ Which network users and applications require control system access?
- ✔ What do they need access to?
- ✔ What type of remote access does the user require (e.g., dial-up, telnet, ftp, X-sessions, PCAnywhere, etc.)?
- ✔ What are the security risks associated with each type of access?
- ✔ Is the information required worth the security risk?
- ✔ Is the password capable of being changed?
- ✔ How often should it be changed?
- ✔ Who is the system administrator?

Make Decisions with the Future in Mind

As we look to the future, it seems the time between the present and the future is shrinking. When a PC bought today is made obsolete in six months by a new model with twice the performance at less cost, how can you protect the investments in technology you make today? Obviously, there is no way you can keep up on a continuous basis with all the technology developments in all areas. You must rely on others to keep you informed, and who you select to keep you informed is critical. With every purchase, you must evaluate not only the supplier's present products but also its future product development plans.

- ✔ Does the supplier continuously enhance and upgrade products?
- ✔ Is the supplier developing new products to meet future needs?
- ✔ Do existing products have a migration path to enhanced and new products?

Selecting the right supplier will ensure you stay informed about new and future industry developments and trends and will allow you to access new technologies with the least impact on your current operation.

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Biography

John D. McDonald received his B.S. and M.S. degrees in electrical engineering from Purdue University and an MBA from the University of California at Berkeley. As senior principal consultant and manager of Automation, Reliability, and Asset Management for KEMA Consulting, he assists electric utilities in substation integration and automation, distribution management systems, distribution SCADA systems, and communication protocols. He is a Fellow of the IEEE, secretary of the IEEE PES, past-chair of the IEEE PES Substations Committee, and recipient of the IEEE Millennium Medal in 2000 and the IEEE PES Award for Excellence in Power Distribution Engineering in 2002. He gives tutorials and seminars in substation automation, distribution SCADA, and communications for various IEEE PES local chapters as an IEEE PES Distinguished Lecturer. He was editor of the "Substations" chapter and a coauthor for the book *The Electric Power Engineering Handbook*, cosponsored by the IEEE PES and published by the CRC Press in 2000. He is editor-in-chief and author of the "Substation Integration and Automation" chapter for the book *The Electric Power Substation Engineering Handbook*, to be published by the CRC Press in 2003.

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Embracing Holistic Data Management Prepares Utilities for the 21st Century: How power utilities can best manage data in the future, and be transformed

By John D. McDonald, P.E.

GE Power's Grid Solutions business

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Abstract

Data is the new enabler of value in the electric power industry. Though the power industry has always relied on data, the proliferation of sensors and actuators on the grid for improved monitoring and control is among drivers of data on an unprecedented scale. That scale is forecast to increase significantly with the advent of customer involvement in transactive energy markets and the harnessing of external data sources provided by the Internet of Things. These trends call for utilities to take a forward-looking, holistic approach to data management. This paper explores the challenges of such an approach, describes practical steps in achieving it, and how that leads to value creation in operations and the enterprise. The paper also explores how the pursuit of holistic data management drives change in business processes, organizational structure and even business models and how to manage those changes for competitive advantage.

Introduction

Data is an enabler of value[1.] Though that statement probably has always been true, the proliferation of sensors and data sources and our rapidly increasing ability to process data for actionable insights in recent years has placed data and its insights at the core of most enterprises and, indeed, our daily lives.

In a static world, that fact alone would motivate power utilities to embrace the collection, analysis and application of data and its insights. In the dynamic, even volatile world of power utilities at this juncture and looking ahead, however, the proper management of data is also the lifeblood of operational safety, reliability and efficiency, and enterprise value creation.

The takeaway, stated simply, is that a holistic approach to data management is the means to survive and thrive. The key word is "holistic," which implies that a utility should consider the totality of its operations and enterprise activities and their goals as it crafts its approach to data management. A holistic approach means that any authorized person in operations or the enterprise should have secure access to data on demand from any and all sources for the purpose of value creation.

A holistic approach to data management is guided by the need to align customer needs and expectations with utility business drivers. A utility's technology roadmap for grid modernization should support this alignment. If this goal is realized, stakeholder and shareholder expectations will likely be met as well.

What's new for the power industry is the speed, scale and granularity of available data and our rapidly increasing ability to analyze it and apply its actionable insights. Today, nearly every group within a utility organization, on both operations and enterprise sides, should be seeking to optimize their work and gain competitive advantages through data.

As we'll see, the very process of becoming a data-driven utility will transform the utility organization, how it operates and maintains the grid, how it pursues enterprise value creation – even how it adapts its business model to capture future market opportunities. Such an existential transformation can be experienced as a series of discoveries and surprises and arduous adaptations. Or it can be anticipated, embraced and orchestrated for maximum benefit.

On the question of what constitutes the "future," creating an arbitrary timeline and forecasting when utilities will achieve holistic data management yields little benefit. Every utility will pursue its future in data management as it is motivated by its own sense of urgency and as it sees practical gains from data-driven practices and strategies.

The process is likely to be incremental. First, each utility group will improve the return-on-investment (ROI) for every sensor or intelligent electronic device (IED) in its bailiwick by sharing its data with anyone in operations or the enterprise who can use it for value creation. The same logic will then be applied to systems. Both steps require organization-wide cooperation, which delivers a significant, related benefit: silos – long embedded in utility culture, but the bane of effective practices – become passé. Then, as each group within a utility applies the concept of holistic data management, the focus will shift from the success of individual groups to how they cooperate to drive the overall success of the enterprise. Silos crumble, business processes change, and power utilities will emerge better able to thrive and compete in a diverse, disruptive energy marketplace that is now emerging. For the purposes of this paper, this step-by-step evolution may be thought of as "the future."

This paper offers a high-level view of the concepts, pertinent steps, and challenges in pursuing holistic data management. It provides examples of data-driven value creation. And it offers insights into change management. Along the way, we'll spotlight valuable new sources of data from sources such as unmanned aerial vehicles (UAVs) and robotics and suggest how these nascent tools should be woven into a holistic data management approach.

Drivers

Readers undoubtedly are familiar with many of the drivers of big data. Let's name a few, recognize that they may well multiply over time, identify two new sources now being implemented and glance over the time horizon for other impending trends.

Historically, transmission lines and substations have been effectively monitored and controlled due to their key role in moving high-voltage power over long distances, thus their data streams are critical to overall grid operations and therefore familiar. Synchrophasors represent a relatively new addition on the transmission system, and have been deployed initially for wide-area situational awareness. The trend towards system-wide optimization and a more market-oriented approach to power will eventually lead to treating transmission and distribution as a single entity with its own set of data management challenges.

Until that consolidation occurs, however, the historic lack of visibility on the distribution system has driven a surge in monitoring and control in distribution substations, feeders and customer premises. For instance, SCADA systems have been augmented by integrated networks of intelligent electronic devices (IEDs) in substations and on feeders. These IEDs have largely replaced analog monitoring and control devices and include voltage, current and fault sensors. The drop in IED costs has accelerated their adoption. IEDs provide both operational and non-operational data, though the latter is under-utilized and will be discussed further in this paper.

The widespread implementation of smart meters on customer premises and advanced metering infrastructure (AMI) has provided data on every customer's energy use at 15-minute intervals, as well as end-of-line voltage readings, last gasps for dying meters and power quality information – all providing rising streams of data for operations and enterprise use.

Developments such as more frequent, extreme weather underscore the value of greater visibility, monitoring and control, and applications such as integrated volt-VAR control (IVVR) and fault detection, isolation, and restoration (FDIR) depend on that monitoring and control data.

The trend towards deregulation and a shift towards more competitive power markets, including the eventual realization of transactive energy markets, is also driving utilities to obtain, analyze and apply data to optimize operations and support value creation in the enterprise.

The ascendance of end-users from "ratepayers" to "customers" – with rising expectations for service quality and options in a digital age – is driving utilities to analyze end-user data to induce customers to engage and participate in utility programs and service options. That data includes customers' social media use, which can and should be harnessed to, for instance, locate and understand the cause of outages. Getting this piece correctly is particularly important as millennials go mobile and drop landline phone service.

Power utility use of UAVs and robotics is in its infancy, yet utilities that have applied them find that, under specific conditions, these tools can provide a highly effective and efficient means to monitor infrastructure health and even perform remedial work. Though their use is nascent across the power industry, enough progress has been made to recognize that now is the time to apply holistic data management thinking to how their outputs are managed for value creation.

Emerging on the horizon is the network of networks known as the Internet of Things (IoT), which will enable utilities to take advantage of myriad, external data streams relevant to their operations and enterprise, with attendant cyber security risks to industrial control systems and enterprise networks.

Pursuing a holistic data management approach is likely to transform utilities into data-driven organizations capable of navigating present and future technology and market trends, but these benefits invariably involve overcoming both traditional and new challenges in organizational practices and culture.

Challenges

The fundamental challenge to adopting a holistic data management approach is overcoming resistance to organizational culture change. The effort required to overcome tradition and its inertia should not be underestimated. Power utilities are by no means unique in this regard, but they are replete with silos at a juncture when silos have outlived their usefulness. The most prominent, but by no means only, silos are those that separate operations technology (OT) and information technology (IT). Integrating and supporting the networks of IEDs, sensors and meters that produce data and designing and operating the information and communications technology (ICT) foundation needed for holistic data management requires IT/OT cooperation and collaboration, if not convergence.

As we'll see, however, all operations and enterprise units have a stake in the process of holistic data management and its outcomes, so the cooperation and collaboration of all units across the entire organization are prerequisite to success. The guiding mantra should be that all authorized utility personnel who can create value from data should have secure access to that data. This egalitarian approach is not mere fairness; it ensures that every technology purchase has the best possible ROI, as will become apparent in the next section of this paper.

Overcoming deeply embedded utility culture requires determination, prioritization and some heavy lifting from within and without. The definition of inertia is, essentially, that things remain the same unless affected by an outside force. Internally, cultural change must be driven by top-tier executive leadership that establishes holistic data management as an organizational priority. An external force is also likely to be effective. Often a neutral third-party with no "political baggage" is needed to facilitate the steps outlined in this paper. This external force must be a trusted advisor with deep knowledge and experience in both holistic data management and change management. Select one carefully; check their credentials, ask hard questions, look for authentic cases that document their claims.

A utility that embarks on holistic data management must develop an appetite for change, a willingness to proceed in good faith across the organization, and the expectation that achieving the fundamentals will lead to ongoing organizational and business model evolution. Meeting these myriad challenges requires a major cultural shift, but that's a prerequisite for success in an era of rapid change, challenges from third-party energy service companies, rising customer expectations and a more competitive landscape.

A step-by-step approach

The relevance of the foregoing points becomes clearer as we take a high-level look at the steps needed to achieve holistic data management.

A utility's foundation must be *strong* before it can be *smart*[2]. That means that its ICT foundation must embrace open architectures and standards, which ensure interoperability and backwards and forwards compatibility between devices, networks and databases. This approach retains the value of legacy technology investments while ensuring full value from current and future investments.

IT and communications groups must work closely to determine the functional requirements (response requirements, bandwidth, latency) of each data path, from sensor to end-user, for all current systems and applications, as well as anticipating future needs. This ICT foundation will link all operational and enterprise aspects of the utility to support full information flow, data management and analytics, grid monitoring and control and enterprise initiatives. It should also support future functionalities such as the integration of distributed energy resources (DERs), new customer services and other needs. The efficacy of seeking a "strong" grid before a "smart" grid is illustrated by lessons learned from projects accomplished under the American Recovery and Reinvestment Act (ARRA) between 2009 and the present.

ARRA, enacted in 2009, enabled many utilities to adopt AMI and install interval meters at the customer premise. Some utilities assigned implementation to their metering group. Later, in implementing distribution automation (DA), these same utilities assigned DA to a distribution engineering group in operations. Alas, these utilities found that the data networks and IT infrastructure supporting AMI did not support DA or required a costly, arduous work-around. A holistic data management approach would have required the metering group and the distribution engineering group to share their goals and, ultimately, to design and build a service territory-wide communication network to support both initiatives and avoid redundancy and complexity and vastly improve ROI[3].

This specific example supports the holistic approach that requires that all operational and enterprise units convene over their future projects and agree on foundational ICT requirements that will serve them all. The result is culture change in motion, driven by a common-sense approach to a strong ICT foundation and optimized business case.

Integration before automation

Distribution system integration means tying together protection, control and data acquisition functions via the fewest number of platforms to reduce costs, footprint and possible redundancies in equipment and databases. The mantra: keep it simple and use the fewest and most optimal functional data paths from sensor to end-user.

The integration of data-producing devices and systems is the next step after building a strong ICT foundation. Integration should precede substation automation, which refers to implementing SCADA, alarm processing and other elements to optimize asset management and operational efficiencies on the distribution system[4].

The next step in holistic data management is to map data from sensor to end user. This requires IT/OT cooperation and collaboration to support the acquisition, transport, storage, analysis, and delivery of data to the right person at the right time for the right reasons.

Understanding IEDs' non-operational data

Let's begin at the device or sensor level. IEDs are rapidly replacing analog devices because, among other reasons, they produce two useful data streams. As most readers know, an IED may be a standalone sensor or a data-producing substation protection and control device such as a protective relay, load tap changer, voltage regulator, etc. An IED's operational data is routed in real time to control center operators to optimize monitoring and control functions.

But the value of an IED's nonoperational data is too often overlooked. Nonoperational data can fuel significant insights for value creation, if it is routed, stored, processed and made accessible to a utility's enterprise groups.

For instance, nonoperational data can drive enterprise goals for energy efficiency, load shaping and capital deferral. Interval meter data (another form of nonoperational data) can support energy efficiency and reliability programs such as demand response and dynamic pricing. The use of nonoperational data also enables a utility to move from time-based to condition-based asset management because that data tells maintenance when, for instance, a breaker is due for service based on the device's functional history.

Though the price of IEDs is dropping, they remain expensive, in the four- and five-figure range. An IEDs' ROI improves markedly when both operational and nonoperational data are fully exploited to achieve value.

As the routing and use of operational data is well-known, we'll focus instead on a holistic data management approach to nonoperational data. In doing so, we'll demonstrate the efficacy of a holistic approach. The following description is a brief, simplified overview; the cited sources provide greater detail for readers who wish to delve deeper.

From data maps to data marts

The process immediately requires that people talk to people and cooperate across organizational lines for the greater good. Business unit managers need to understand who in their unit needs nonoperational data as well as what specific nonoperational data is available. Managers may need technical assistance from IT/OT to fully grasp the nature of available data and how it can be used in value creation.

Each IED provides a collection of data-producing points typically referred to as “data maps.” An inventory of IEDs and their data maps can help managers grasp what types of data are available and who needs it for enterprise-wide value creation.

This step is potentially complex. IEDs’ data maps need careful documentation because different vendors’ IEDs capture and render different nonoperational data in different ways – this is known as an IED’s “attributes.” Data creation might occur at a predetermined sampling rate, when a preset threshold is exceeded, or it could be event-driven. An IED’s attributes must be understood for the data to be useful to an end-user.

Matching data sources with authorized end-users creates an enterprise-wide “data requirements matrix,” based on an IED template (the sensors and their data maps) and the needs of end-users. This data requirements matrix guides the network architecture that sends nonoperational data across the corporate firewall into a data repository/warehouse on the corporate network for end-users to access on-demand. Rigor and accuracy in this phase is critical to a successful outcome.

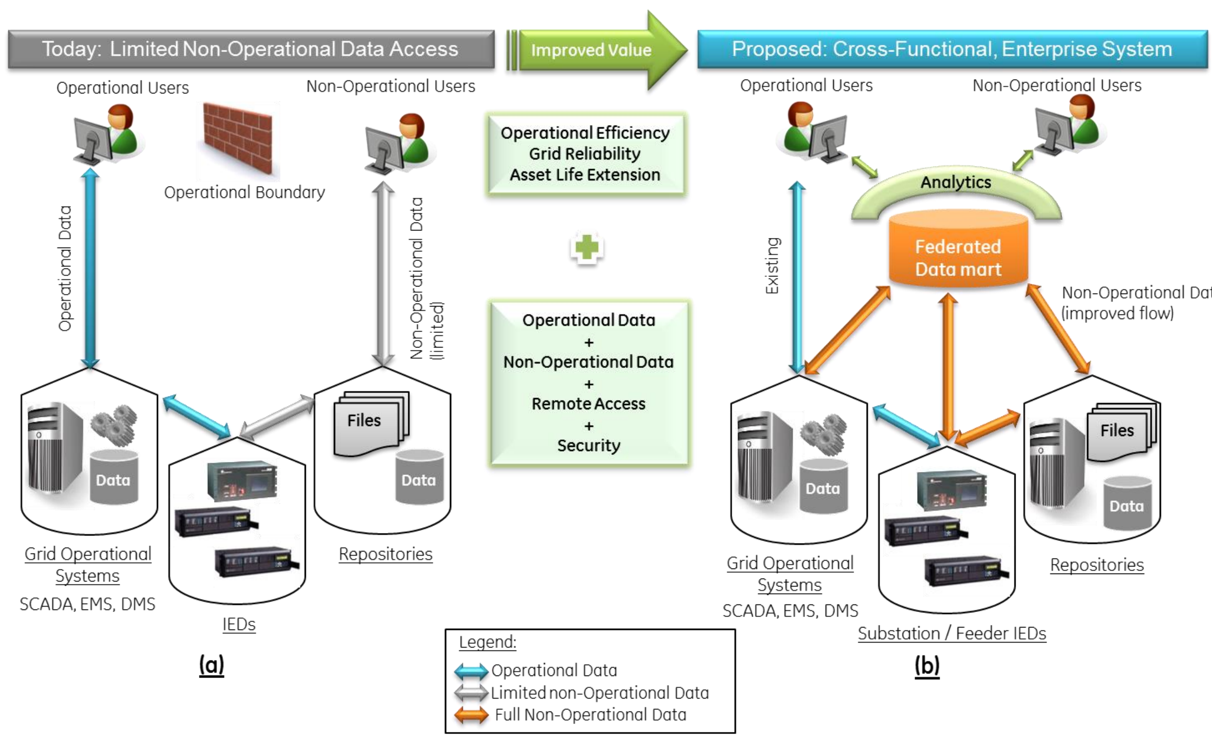

Figure 1. Common, current siloed practices vis-à-vis access to nonoperational data are depicted on the left. The use of a federated data mart to access nonoperational data holistically is depicted on the right. (Source: GE Grid Solutions)

Because utilities typically maintain several physical data repositories, a federated data server can sit atop those repositories (retaining the value of legacy infrastructure) and create a "virtual data mart," or unified retrieval system. The data mart also contains operational data received from the operations (SCADA) historian, which records operational data at a predetermined sampling rate for export across the firewall to the enterprise[5].

The processes just described require cross-organizational cooperation between IT and OT, operations and enterprise, across all units, groups and departments. So de-siloing is both a prerequisite for the pursuit of holistic data management and an outcome of the process.

Of course, the desired outcome – the right data for the right person at the right time – is subject to data integrity and security measures as well as strict access controls for end-users such as multi-factor authentication. Under those conditions, authorized end users can access data from the data mart on demand for use with their enterprise applications and the results can be presented via dashboards that translate numbers into visually understandable values.

New data source: customers' social media

One of the fundamental aspects of value creation in the enterprise going forward will be to understand and engage customers and meet their needs and expectations with innovative programs that influence customer satisfaction. Nonoperational data will play a role in the pursuit of that goal. In particular, external data sources – namely, customers' social media output – will increasingly play a role. Consider that the fastest-growing demographic group of utility customers is millennials, who overwhelmingly rely on networked mobile devices rather than landline phones. Where utilities once identified and partially analyzed outages through landline calls from their customers, today's and tomorrow's customers are mobile and equipped with social media and high-resolution cameras and video capabilities.

Today, analytical software integrated with a utility's outage management system (OMS) can, for example, mine the content of tweets for information on outages and associate that information with social media imagery. Utilities can and should incentivize their customers to share GPS location data to provide a useful picture of an outage's location and nature, prior to rolling a truck, enabling field crews to be better equipped for a specific challenge and more efficient in addressing it. Improving reliability metrics through speedy power restoration will always be a core utility goal. And it markedly improves the business case for distribution automation, which includes other reliability applications such as IVVC and FDIR.

This approach can be used by utilities without AMI or it can be a useful tool to augment premise-level meter data. A full explanation of how such data is routed and integrated for best results is too detailed for the high-level purposes of this paper, but the accompanying citation provides it[6].

As the number of customers engaged in such a process increases, so does the quality and value of the data and insights that emerge. Research reveals that the more engaged customers are, the more satisfied they are with their service and their utility – and the more likely they are to adopt new utility programs for energy efficiency, demand response, and active energy management that serve broader utility goals.

In the overall pursuit of holistic data management, customers' social media output illustrates how a relatively new, external data source can and should be tied into a utility's data management practices for value creation.

Enter: UAVs and robotics

This last point should be embraced, as it appears that the emergence of new sources of data external to both operations and enterprise may well become commonplace. Two new sources of data make this point: unmanned aerial vehicles (UAVs) and robotics.

UAVs are simply one component of what is referred to as unmanned aerial systems (UAS) because they rely on pilots on the ground and a communications link between the two (hence "systems"). Pre-programmed, autonomous UAV flight is also possible, though largely prohibited for utilities at this point. At least in the utility industry, the synonymous, popular term "drone" typically is not used as it has negative connotations as a tool of war or unwarranted surveillance.

"Robotics" is a term that refers to machines that replace humans, backed by sensors, processing capabilities and communication systems, typically for difficult or dangerous tasks.

The LineScout, by MIR Innovation, a subsidiary of Hydro-Québec, inspects a ground wire and 735-kV lines near Ile d'Orléans in the Saint Lawrence River, east of downtown Québec City, Québec, Canada. Photo credit: Hydro-Québec

Though some utilities, in time-honored "fast follower" power industry tradition, may opt to let these emerging technologies and their market sector develop without taking action, I'd argue for the opposite approach.

As noted, power utilities face existential threats from the march of technology and market forces. They do not have the luxury of repeating past mistakes by not applying a firm hand to manage and shape emerging technologies to their advantage. The pursuit and application of holistic data management practices for UAVs and robotics would seem imperative in an increasingly competitive energy marketplace rattled by disruptive forces.

A brief, ad hoc survey of utilities, consultants and power industry consortia in late 2017 revealed how a coordinated industry response to the emergence of UAVs and robotics could speed time-to-value[7]. But let's first look at this fascinating, emerging field and the diverse approaches that utilities are taking to it and its resulting data.

At this point, a few generalities appear possible. Currently, various utilities are exploring the available technologies and their capabilities and identifying potential use cases, while assessing value propositions and business cases. If properly harnessed and integrated into existing utility programs, UAVs and robotics promise to efficiently and safely perform tasks ordinarily too difficult or dangerous for humans or as an alternative to expensive, sometimes dangerous manned aerial reconnaissance. Asset inspection, damage assessment, non-destructive testing, live-line maintenance and other tasks are possible with UAVs and robotics. The current focus of UAV use tends to be on transmission lines, due to scale and ample rights-of-way clearances. But robotics are also being used underwater to inspect and perform remedial work on turbines in hydroelectric dams.

Already it's clear that the power industry will benefit from influencing UAV policy. The Federal Aviation Administration (FAA) has strict rules regarding pilot certification, beyond line of sight (BLOS) uses and autonomous (non-piloted) flight. Though a waiver process is available, several utilities cited current policies disallowing BLOS and autonomous flight as barriers to a positive business case for UAVs. That said, it's apparent that a positive business case depends on multiple factors and that cost-effective, targeted UAV and robotics roles are likely to emerge in the context of broader, asset-related utility programs.

It's also clear that we're seeing spasms of activity typical of emerging technologies, in the sense that work on related standards is not yet feasible in a heterogeneous, rapidly evolving marketplace for both UAVs and robotics.

In order to glimpse the potential for the use of UAVs, readers would profit from exploring what Southern Company, Dominion Energy, Hydro-Québec, Xcel Energy and Duke Energy – among many others – are doing.

The LineRover remote-controlled robot (right), by MIR Innovation, a subsidiary of Hydro-Québec, tows the LineCore sensor during a conductor inspection. Photo credit: Hydro-Québec

(In the course of preparing this paper, I spoke with Renato Salvaleon, information systems analyst, Alabama Power Company/Southern Company (and team lead for the IEEE Power and Energy Society's UAS geospatial data management task force); Steve Eisenrauch, manager of transmission forestry and line services, Dominion Energy; Serge Montambault, Manager – Inspection and Maintenance Robotics, Hydro-Québec Research Institute; and Andy Stewart, president, EDM International, Inc. I gratefully acknowledge their contribution to this paper, though the conclusions drawn here are my own.)

Industry consortia, including EPRI, IEEE and EEI, are currently at work on various UAV- and robotics-related initiatives. The foci, generally speaking, include an assessment of market offerings, utility best practices and automated image analysis, though very targeted applications and practices are being explored as well.

(In preparing this paper, I spoke with Drew McGuire, program manager, and Dexter Lewis, senior technical leader, both at EPRI. I gratefully acknowledge their contributions.)

To grasp the cutting-edge of robotics work, I'd recommend visiting a single, well-illustrated source: MIR Innovation, a subsidiary of Hydro-Québec. As an engineer, I'm astounded by the capabilities of robotics at this stage. The bigger picture, of course, is what these amazing technologies provide us with in terms of data and that data's relationship to value creation.

UAV equipped with LineCore sensor, by MIR Innovation, a subsidiary of Hydro-Québec, that is able to detect the first signs of conductor corrosion in a non-destructive way. Photo credit: Hydro-Québec

The challenge: wag the dog

UAVs and robotics are here now, moving rapidly towards commercial application, so it behooves us to explore the data management challenge that comes with them.

Generally speaking, UAVs and, to some extent, robotics, produce data from a variety of sources, including but not limited to video, still photography, LiDar and PhoDar imagery and infrared sensors.

From my ad hoc survey, I learned that UAV video imagery is often streamed live in low-resolution to guide a pilot and, in some cases, to inform a utility infrastructure inspector who might be making real-time analyses of asset health, subsequently vetted by more granular, post-flight vetting. High-resolution data from cameras and other sensors typically is stored on an onboard memory card for later download to a corporate network for storage and analysis.

As with many tools, utilities are beginning to manage UAV and robotics data in myriad ways, with no clear pattern yet emerging. This data is variously being used to inform asset management programs, geographic information systems (GIS), outage management systems (OMS), storm damage assessments, and construction site assessments. Advanced robotics are even performing in situ, live-line, non-destructive testing and remedial work on overhead lines as well as underwater hydroelectric power turbines.

So, how are utilities handling this data?

On the analysis side, the pursuit of automated image analysis promises to create value; having humans watching hours of streaming video is not practical or a beneficial use of resources. Presumably, the other data sources from UAVs and robotics also require processing for value creation.

Given the thesis for this paper, we must ask how raw and analyzed data from UAVs and robotics is stored, routed or otherwise made available across the utility organization. Again, my brief, ad hoc survey reveals a wide range of practices. One utility I spoke to houses its UAV/robotics program under a transmission maintenance group, which currently does not share the data with other operations or enterprise units. At the other end of the spectrum, one consultant is encouraging his clients to take an approach captured by the apt phrase "one flight, many uses" – i.e., sharing UAV/robotics data for its widest possible use benefits the utility in diverse ways and improves the business case.

Per my thesis on the organization-wide benefits of holistic data management, you'll understand why I favor the latter approach. I'd suggest that these emerging technologies offer yet another opportunity to de-silo a utility and its approach to data management to achieve the organization-wide value creation that creates a positive business case for new technologies and makes a power utility more nimble and competitive.

Meanwhile, utilities must decide whether to proceed with these emerging technologies in-house or turn to a third-party. As UAV vendors extend their offerings to include data analysis, as a value-add, utilities should be wary of proprietary solutions that ultimately limit their future options.

Let me be clear: the free market is a font of innovation and competition that offers diverse choices and that's generally beneficial. But it is important that power utilities continue to pursue and support the technologies, policies and standards that will create a positive business case for UAVs and robotics and the organization-wide value – indeed, the industry-wide value – they can create.

It is perhaps perilous to suggest prescriptive steps this early in the process. But a general observation is pertinent: power utilities en masse, through their representative organizations and programs dedicated to these emerging technologies, can exert their influence to shorten time-to-value in this area by ensuring that UAV and robotics vendors meet utility needs and requirements and not the other way around.

Innovation and differentiated services and solutions may be beneficial up to a point, but proprietary solutions historically have proven to be problematic, leading to vendor lock-in, stranded assets, isolated systems, unusable data, high costs and wasted time.

Thus, I humbly suggest that the power industry determine and pursue common requirements for these technologies and push UAV and robotics purveyors to meet them. This would include the adoption of standard data formats, data analytics based on open source architectures, and true enterprise wide integration of the information. If the power industry determines its particular needs – as opposed to, say, other industry verticals using UAVs and robotics – and uses its heft to bring vendors around to meet its requirements, adoption rates will grow and benefit both parties. Eventually, the power industry will coalesce around a variety of needed standards and the market will benefit from interoperability and economies of scale, further accelerating market adoption.

Conclusion: urgency needed

The other half of the equation is the sole responsibility of individual utilities. The emergence of UAVs and robotics presents a perfect opportunity to put holistic data management into action. Clearly, from the concepts and steps outlined in this paper, a strong ICT foundation must be in place before a utility can leverage new data sources for value creation. There is no better time – no more urgent time – to begin that journey than right now.

Perhaps UAVs and robotics appear too esoteric at this point to ignite a sense of urgency. But the IoT is not far behind, if it isn't here now. The IoT and its network of networks, all hosting innumerable devices and nodes, all generating myriad sources of potentially valuable data, will make preparations for UAV and robotics data look like child's play.

In a data-driven world, with proliferating energy options for utility customers, rising third-party competition, disruptive technologies and policy shifts all inevitable, it seems critical to lay the foundation of a strong grid, add intelligence and ensure that data from both traditional and emerging sources is fully exploited across the organization for value creation.

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Biography

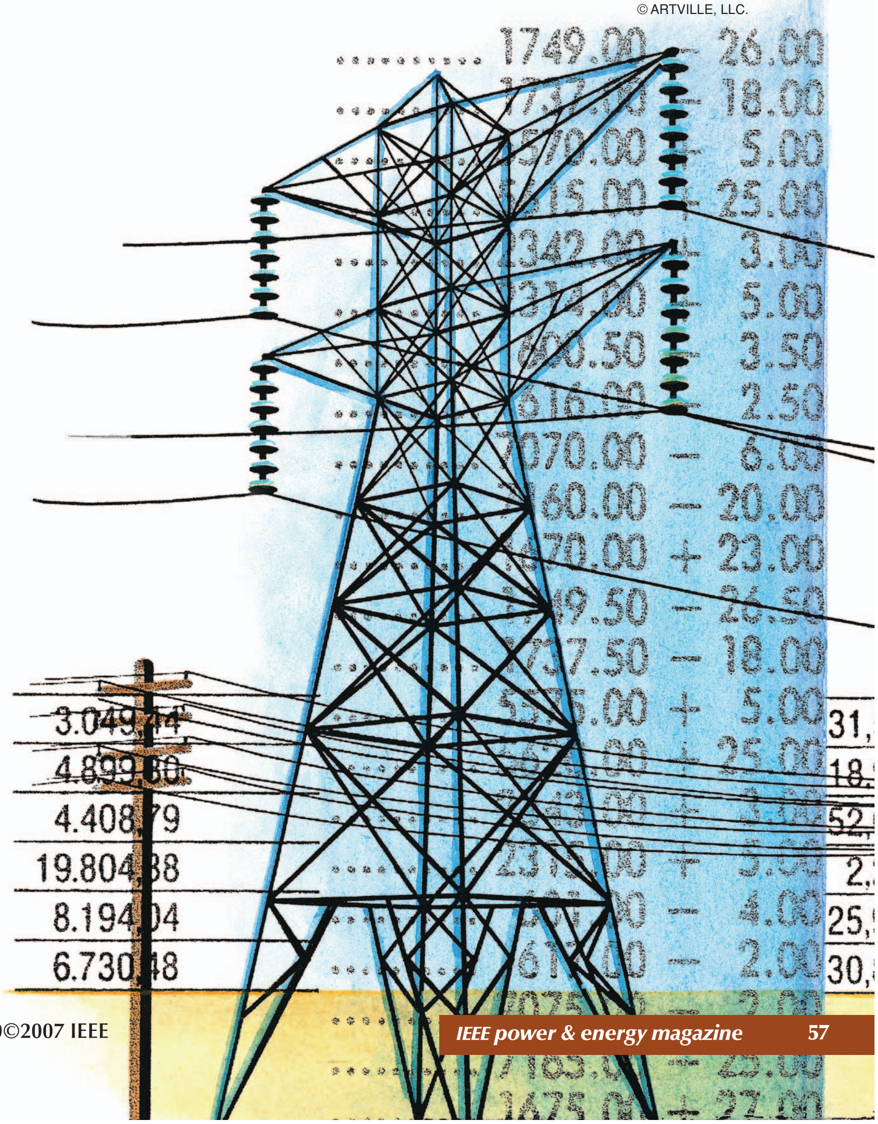
John D. McDonald, P.E., is Smart Grid Business Development Leader for GE Power’s Grid Solutions business. John has 43 years of experience in the electric utility transmission and distribution industry.

John is a Life Fellow of IEEE, and was awarded the IEEE Millennium Medal, the IEEE Power & Energy Society (PES) Excellence in Power Distribution Engineering Award, the IEEE PES Substations Committee Distinguished Service Award, the IEEE PES Meritorious Service Award, the 2015 CIGRE Distinguished Member Award and the 2015 CIGRE USNC Attwood Associate Award. John is Past President of the IEEE PES, the VP for Technical Activities for the US National Committee (USNC) of CIGRE, the Past Chair of the IEEE PES Substations Committee, and a member of the NIST Smart Grid Advisory Committee. John was elected to the Board of Governors of the IEEE-SA (Standards Association), focusing on long term IEEE Smart Grid standards strategy. John received the 2009 Outstanding Electrical and Computer Engineer Award from Purdue University. John teaches a Smart Grid course at the Georgia Institute of Technology, a Smart Grid course for GE, and Smart Grid courses for various IEEE PES local chapters as an IEEE PES Distinguished Lecturer. John has published eighty papers and articles and has co-authored five books.

John received his B.S.E.E. and M.S.E.E. (Power Engineering) degrees from Purdue University, and an M.B.A. (Finance) degree from the University of California-Berkeley.

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,

by John D. McDonald, Shankar Rajagopalan, Jack R. Waizenegger, and Fernando Pardo

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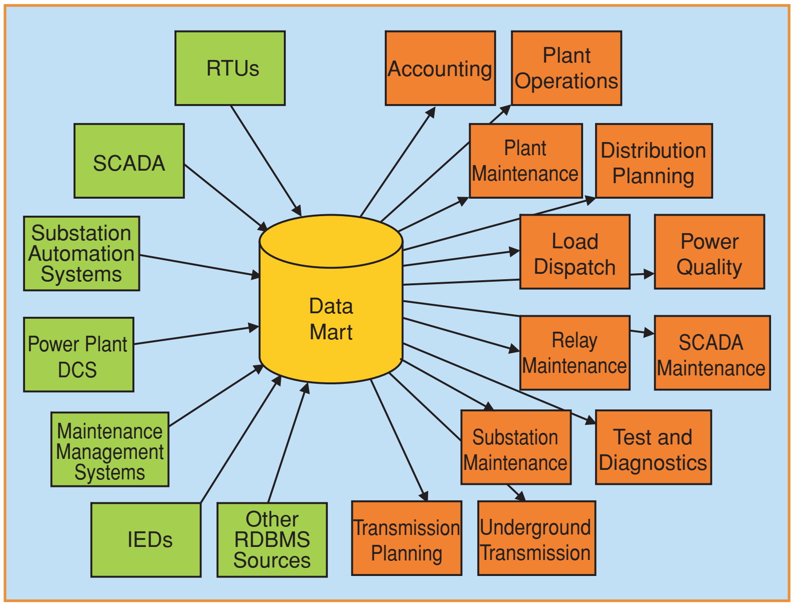


figure 1. Data mart architecture. Data flow into the data warehouse from all data sources and are available for desktop access to all users within the large number of user groups.

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.

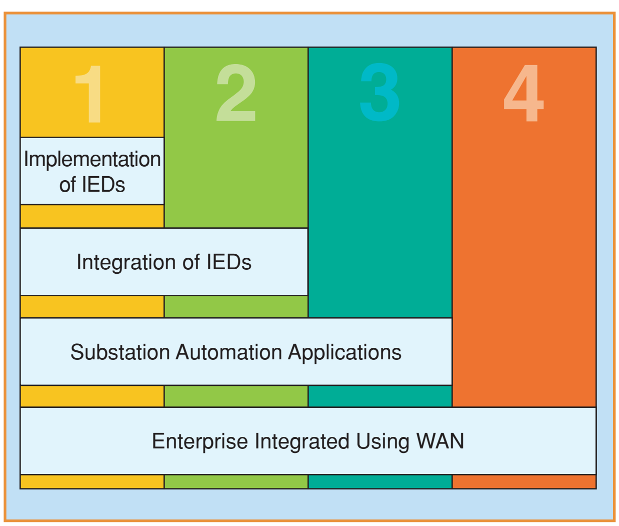


figure 2. Levels of integration. The data warehouse will be fully integrated with the maintenance management system to move to the stage of "Just-in-Time" condition-based maintenance.

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.

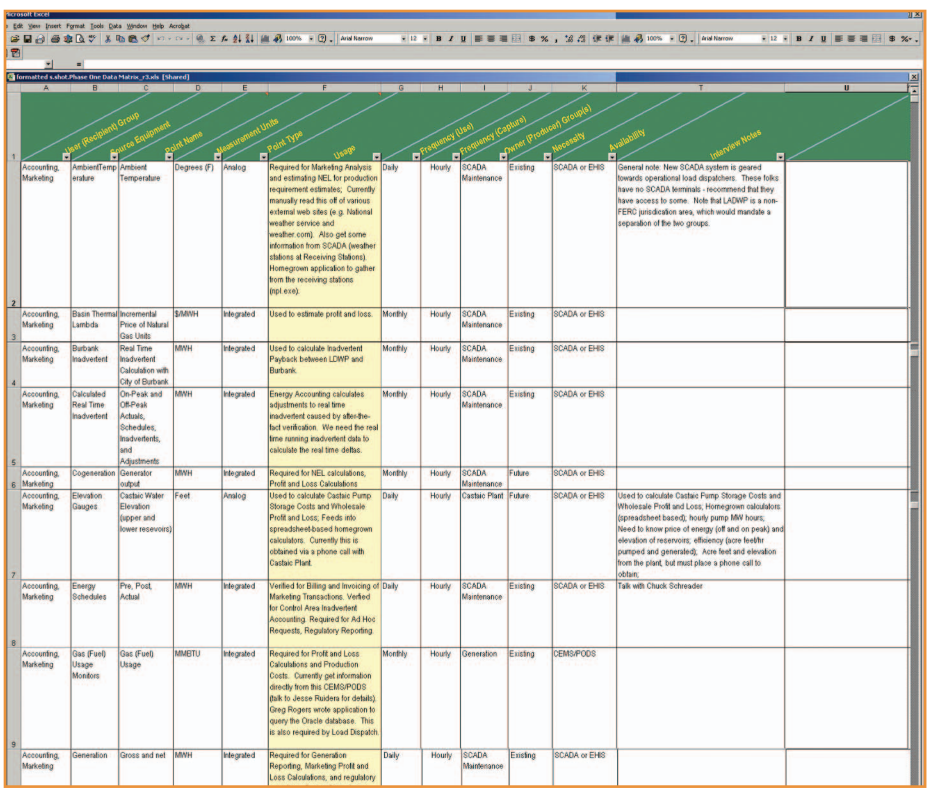
makers. Rather than lump these individuals into their predefined departments, the consulting firm suggested grouping the users into informal clusters based on job function, applying the notion that similar functions require the same information.

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
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.
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	
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	
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	
Accounting, Marketing	Cogeneration	Generator output	MWH	Integrated	Required for NEL calculations, Profit and Loss Calculations	Monthly	Hourly	SCADA Maintenance	Future	SCADA or EHIS	
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;
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
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

This information gap can be bridged with a corporate data mart, carefully designed data paths, and well-documented end-user information needs.

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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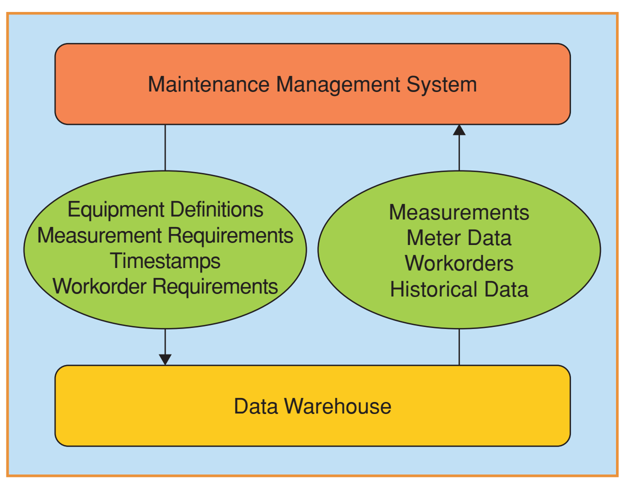

figure 4. Integration with the maintenance management system. Typical levels of integration within the enterprise based on various stages of technological development.

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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Biographies

John D. McDonald is vice president of automation-power system automation for KEMA, Inc., with 33 years of experience in the electric utility industry. He is currently assisting electric utilities in substation automation, distribution SCADA, communication protocols, and SCADA/DMS. He received his B.S.E.E. and M.S.E.E. (power engineering) from Purdue University and an M.B.A. (finance) from the University of California-Berkeley. He is a Fellow of IEEE and was awarded the IEEE Millennium Medal in 2000, the IEEE PES Excellence in Power Distribution Engineering Award in 2002, and the IEEE PES Substations Committee Distinguished Service Award in 2003. He is president of the IEEE Power Engineering Society and past chair of the IEEE PES Substations Committee. He is editor-in-chief, and author of the Substation Integration and Automation chapter, for the book *Electric Power Substations Engineering* (Taylor & Francis/CRC Press, 2003).

Shankar Rajagopalan is an associate in KEMA's Energy Systems Consulting group. He has over ten years of experience specializing in strategic technology solutions in the energy and utilities sector. He has extensive experience in the design, development, systems integration, and implementation of energy trading and risk management applications and business intelligence/data warehouse solutions. His functional background includes energy trading and risk management, procurement, and financial systems. Prior to KEMA, he was director of business intelligence at SungGard Energy Systems.

Jack R. Waizenegger of the Los Angles Department of Water and Power is a professional engineer and a licensed general contractor. He has a B.S. in electrical engineering for the University of Florida and an M.S. in electrical engineering (power systems) and an M.S. in engineering management from the University of Southern California. He has worked for 26 years at the Los Angles Department of Water and Power. He has had various design and construction position in generation, transmission, and distribution. He was the manager of the Energy Control System Upgrade Project. This project includes SCADA, substation automation, distribution automation, and related communication systems. He is presently the manager of Laboratory and Technical Testing Services.

Fernando Pardo of the Los Angles Department of Water and Power is a professional engineer. He has a B.S in electrical engineering from California State University Los Angeles, an M.S in electrical engineering (power systems) from University of Southern California, and an M.B.A. from Pepperdine University. Fernando has worked for 27 years at the Los Angeles Department of Water and Power in various assignments in the design, planning, and operation of generation, transmission, and distribution systems. He is currently the manager of Geographic Information System Projects and has worked in the implementation of SCADA, outage management, work management, and other power system automation applications.