Forum Proceedings

Albuquerque, NM • November 7-9, 2007

Grid-Interop™

GRIDWISE™ Architecture Council

PNNL-SA-58499

LETTER FROM THE CHAIR

December 14, 2007

Grid-Interop Participants and Interested Colleagues:

Thank you to those who attended in the first Grid-Interop Forum. Throughout the event, we were amazed at the level of engagement. With over 90 speakers of the 160 registered attendees, we predicted an event with active participation; however, the level of attentive discussion heard in the sessions, breaks, and meals exceeded our expectations. Though the audience came from diverse backgrounds such as buildings, manufacturing, electricity delivery, and regulatory policy, the theme of interoperability and the issues associated with it, proved powerful in its ability to transcend industry segments and bring people together to address a common cause: how to make our electricity systems and components connect and talk more easily and effectively.

We are pleased to offer a record of this event in the following proceedings material. It contains the compendium of papers produced for the event, as well as the panel session abstracts and links to the presentation slides. We have also summarized the results of the six action roundtable sessions. These sessions produced many good proposals for advancing interoperability that will require our continued interaction.

To our friends who were unable to attend, we regret that your perspectives and insights were not heard at the meeting. However, given the need for continued engagement in actions such as proposed in the roundtable sessions, we hope you will review these proceedings with an eye to engage yourselves and your organizations in these developing activities.

Given the high level of interaction and the large body of work before us, the GridWise Architecture Council in consort with Clasma Events is beginning to develop plans for Grid-Interop 2008. More information will be forthcoming about that.

A closing word of deep appreciation to the event sponsors whose support made this meeting possible and to the many volunteers, authors, and speakers whose hard work and commitment was responsible for the high quality of the sessions.

We hope to see all of this year's participants again at Grid-Interop 2008, and for those who did not attend, we hope you will join us in coming events and activities.

Best regards,

Jack Mc Gowan
GWAC Chair

Steve Widergren
GWAC Administrator

Ron Ambrosio
Manager, Internet-scale Control Systems
IBM T.J. Watson Research Center

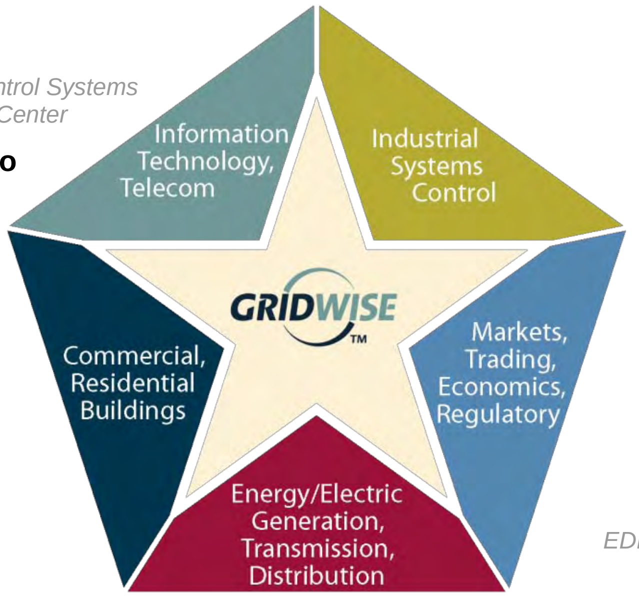
Joseph (Joe) Bucciero
Senior Vice President
KEMA Incorporated

David Cohen
CEO
Infotility

Rik Drummond
CEO and Chief Scientist
Drummond Group Inc.

Erich Gunther
Chief Technology Officer
EnerNex Corporation

Stephanie Hamilton
Distributed Energy Resources Manager
Southern California Edison (SCE)



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Lynne Kiesling
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Russell Robertson
Manager, Control Systems
Tennessee Valley Authority

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Alison Silverstein
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President, Energy Control Inc.
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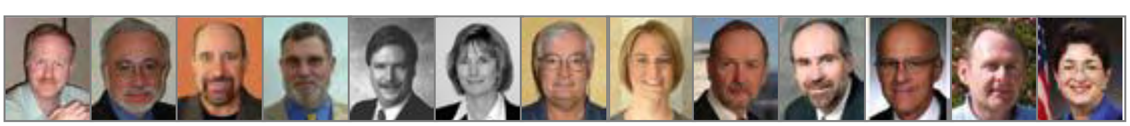
Grid-Interop
http://www.grid-interop.com

GridWise Architecture Council:
http://gridwiseac.org

Pacific Northwest National Laboratory:
http://www.pnl.gov

DOE EERE:
http://www.energy.gov/energyefficiency/index.htm



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INTRODUCTION

The Grid-Interop Forum was a first-of-its-kind event that was 18 months in the making and brought together a diverse audience of stakeholders in creating an interactive electric system that allows all resources to participate in its effective operation.

The process began with work by the GridWise Architecture Council to develop a context-setting framework to facilitate discussion about interoperability of the emerging intelligent systems and advance efforts to simplify or ease the integration of these systems in a safe and reliable manner to the overall electric system.

The GridWise Interoperability Context-Setting Framework document became the main topic for a workshop of 55 systems of systems integration experts who met in Dallas, Texas in April, 2007 to review and revise the draft framework document. This meeting also cemented the Architecture Council's plans to hold a more general forum that would engage those with a stake in the electric system on gaps and issues and proposals for moving forward. A version 1.0 of the framework document was subsequently released in July and became a cornerstone for issuing a call for papers for the first Grid-Interop Forum.

The call for papers exceeded our expectations and brought many new participants to the interoperability cause. Those involved in the workshop and those who developed abstracts, papers, and presentations for the forum became important contributors to creating a compelling meeting.

The structure for the meeting itself came from the ideas generated at the interoperability workshop, and was refined through consultations between an active and creative planning committee. The committee consisted of Ron Ambrosio, Anto Budiardjo, Rik Drummond, Eric Gunther, Dave Hardin, Ron Jarnagin, Terry Mohn, Ruth Taylor, Andreas Tolk, Steve Widergren, and Thomas Yeh. Given the diverse background of the meeting participants and the high number of presenters, three tracks were defined: Architecture, Business, and Technical.

The first set of Grid-Interop sessions was designed to be "foundational". That is, they presented awareness to concepts and material that the planners desired of all participants in a specific track. The main body of the forum consisted of panel sessions also arranged along these tracks. The panel sessions were largely organized thanks to the many abstracts received in the call for papers and supplemented by a few other panels to round out the topics for engagement with all the major stakeholders. In the following pages you will see abstracts describing presentations made in the foundational and panel sessions. These contain links to the presentations made at the meeting. Many authors developed full papers to communicate there important points. These papers are captured in the appendix to these proceedings.

A key purpose for the meeting was to solicit input and resources to develop proposals for activities that will advance interoperability. Action Roundtables were designed to gather those who would champion the cause in the areas of Appliance to Grid, Home to grid, Building to Grid, Industrial to Grid, Enterprise to Grid, and Consumer Side Harmonization. The roundtables were well-attended, active discussions that described gaps, needs, and steps for addressing them. The proposals and actions stemming from these roundtable discussions are also included in the proceedings.

Finally, Grid-Interop was fortunate to have several distinguished speakers, who provided thought provoking insights to relevant aspects of the "smart grid" and interoperability. Keynote, lunch, and dinner speakers are listed in following section as is short description of the closing remarks.

KEYNOTE SPEAKERS

John J. Mc Gowan
Chair, GridWise Architecture Council
President, Energy Control Inc.

The Honorable Jeff Bingaman
United States Senator, New Mexico
Via Video

Jon Wellinghoff
Commissioner, Federal Energy Regulatory Commission (FERC)
Via Video

Matt Smith
Director, Utility of the Future, Duke Energy

Ed Cazalet
CEO and Founder, the Cazalet Group

Michelle Lujan-Grisham
Former Cabinet Secretary of Health, State of New Mexico

INTEROPERABILITY MEGA PANEL

The mega panel of key leaders representing a broad range of industries discussed the need for interoperability and answered questions from Grid-Interop participants.

The mega panel included:

John J. Mc Gowan
President
Energy Control Inc.

Gale Horst
Lead Engineer, Advanced Electronic Applications
Whirlpool Corporation

Paul Nagel
Vice President of Engineering
Control 4

Tom Burke
President and Executive Director
OPC Foundation

Cindy McGill
Senior Vice President of Public Policy and Strategy
PNM Resources

Jim Lee
President
Cimetrics Inc.

Steve Hauser
Vice President
GridPoint

Allan Schurr
VP Strategy
IBM

INTERACTIVE INTEROPERABILITY

Members of the GridWise Architecture Council moderated an interactive session which reviewed the results of a survey conducted prior to Grid-Interop. The session was conducted in a light-hearted game show format. Survey questions included:

- In what timeframe do you expect the broad existence of an interoperable electric grid?
- Which decision maker group will play the primary role in helping to achieve a smart grid?
- What technology area has the most to gain from interoperability?
- What is the scope of Interoperability?
- What is the best role for government in advancing interoperability?
- Who mainly benefits from Interoperability?
- What is the main challenge of Interoperability?
- What electricity consumer groups will benefit first from interoperability?
- What is the Context Setting Framework?

CLOSING PRESENTATIONS

Eric Lightner, DOE
Eric provided an update on related DOE initiatives and spoke to the future of the GridWise program.

David Wells, KPCB
David provided an insight on the investment community's anticipation of sustainability and the Smart Grid.

Fred Mondragón, State of NM
As Secretary for Economic development, Fred outlined the relationship of interoperability and economic growth.

Rik Drummond, GWAC
Rik Drummond, as the GridWise council's representative, recognized the papers in each track which best represented concepts that advance the cause of interoperability.

Recognized Papers:

- Quantum Leap's Jonathan Dale and Apperson Johnson for the paper "Rational Agents for Decentralized Environments,"
- Portland General Electric's Conrad Eustis, Whirlpool's Gale Horst, and Pacific Northwest National Laboratory's Don Hammerstrom for their paper "Appliance Interface for Grid Responses,"
- Cornice Engineering's Gary McNaughton and NRECA's Robert Saint for their paper "Multi-Speak and CIM – A Roadmap to Interoperability."

Steve Widergren
As the Council's administrator, Steve summarized the key actions and assignments from the six Action Roundtables.

REFERENCE DOCUMENTS

Whitepapers
Decision Maker's Checklist (PDF 191KB)
Interoperability Context-Setting Framework (v1.0) Document (PDF 798KB)
Interoperability Path Forward Whitepaper (PDF 77KB)
Interoperability Constitution Whitepaper (PDF 67KB)
GridWise Architecture Tenets and Illustrations (PDF 271KB)

Proceedings
Interoperability Workshop Proceedings, Dallas, TX April 11-12, 2007
Constitutional Convention Proceedings (PDF 1734KB)

Reports
GWAC Summary of Constitution Interview Process and Feedback (PDF 2249KB)

FOUNDATION SESSIONS

ARCHITECTURE FOUNDATIONS

The GridWise Architecture Council took an initial step toward establishing a context for discussing interoperability issues with the Interoperability Context-Setting Framework. The framework provides perspective for architectures & designs for integrating the many interrelated systems in the electric grid. This track was geared for the systems technologist; someone with a general knowledge of system integration and design. In the first session, attendees learned architectural concepts & methods for system of systems engineering. In the second session, methodology and tools that support the processes that take framework concepts into architectures, designs, and solutions was discussed.

ARCHITECTURE FOUNDATION PRESENTATIONS

Name	Presentations
Andreas Tolk	download
Rik Drummond	download
Erich Gunther	download

TRACK LEADER: ANDREAS TOLK; OLD DOMINION UNIVERSITY

ARCHITECTURE, MODEL CONCEPTS

Presented by Andreas Tolk

This session provided an overview of systems engineering processes that characterize the existing state of complex systems and how these systems can evolve to integrate new solutions. The concepts recognize that the current mix of technologies will remain heterogeneous given the enormous size of the electricity environment. The session also highlighted applicable solutions successfully used in other industry domains. The objective is not to design, mandate, or control one set of solutions, but to utilize the collaborative and innovative aspects of the tools to help align ongoing developments, final products, and governing processes.

METHODS & TOOLS

Presented by Rik Drummond and Erich Gunther

Systems engineers and information technologists use an ever maturing set of methods and tools as they move architecture and model concepts into designs and then implementations. This session provided a perspective of methods and tools in practice today to define interfaces and improve integration. It also introduced state-of-the-art approaches that are being introduced in new projects – particularly e-business and internet-based business processes. The results of these approaches promise to simplify integration and improve interoperation, while delivering greater functionality.

Business Foundations

The Business Foundations track introduced interoperability concerns from the business decision-maker's and policymaker's perspective. The sessions described the spectrum of concerns that need to be aligned to allow multiple parties or systems to work together effectively. The first session concentrated on defining interoperability and used real-world examples from the electric power industry and other industries. The second session reviewed a checklist of concerns, designed to help the decision-maker review projects and proposals with interoperation in mind.

Business Foundations Presentations

Name	Presentations
Terry Mohn	download
Alison Silverstein	download

Track Leader: Steve Widergren; Pacific Northwest National Laboratory and GWAC Administrator

Hitchhiker's Guide to the Interoperability Framework

Presented by Terry Mohn & Chris Chen

This session defined interoperability from a business perspective. It introduced the categories that need to be aligned to automate electronic business processes across organizations with emphasis on economic and regulatory policy, business objectives, and implemented procedures. Presented examples demonstrated business collaboration issues to give decision-makers an appreciation for the technical and business integration challenges, as well as the importance of actively addressing these issues. See GridWise Architecture Council's Interoperability Context-Setting Framework.

Decision Maker's Checklists

Presented by Alison Silverstein

The session reviewed the GridWise Architecture Council draft "Interoperability Checklist for Decision Makers". It described the motivation for creating such a checklist and engaged the audience to offer improvements to its comprehension, usability, and context for use. Ideas for future interoperability checklists to target other audiences were also entertained.

Technology Foundations

The technology foundation sessions allowed the conference attendee to see how interoperability concepts and architecture can be implemented through the application of specific standards, technologies, devices, and best practices. Case studies were presented that illustrated how interoperability is achieved in the energy industry through the application of technologies and best practices from other industries.

Technology Foundations Presentations

Name	Presentations
Erich Gunther	download
Jim Butler	download
Grant Gilchrist	download
Ron Farquharson	download
Ron Ambrosio	download
Erich Gunther	download

Track Leader: Erich Gunther; EnerNex Corporation

Field & Device Technologies

This session focused on the technologies and best practices necessary to ensure interoperability among devices from multiple vendors on the energy supplier system, the customer side of the electric and gas meter, and those technologies necessary to create the energy supplier /customer communications interface. The session covered technologies being considered for the implementation of home area networks, utility/consumer portals, demand responsive appliances, and substation and distribution automation. Case studies were also presented that covered the evolution of object oriented command and control technology from the automotive industry to support electric utility substation automation devices, the application of popular Internet technologies such as XML and web services to utility enterprise information models, and technologies that support a viable security policy.

Consumer Portals, Home Area Networks and Connected Devices

Presented by Erich Gunther

This presentation provided an overview of the work underway in various venues related to end use device models and signaling methods that support demand response and other customer interface initiatives.

Achieving Interoperability Using BACnet

Presented by Jim Butler

This presentation focused on technologies and best practices necessary to achieve interoperability in the commercial building space. Particular attention was given to the importance of the BACNET standard.

Field and Device Technologies Substations and Distribution Automation

Presented by Grant Gilchrist

This presentation covered key technologies necessary to achieve interoperability on the utility side of the meter. The technologies include key communications infrastructure technologies, information models, and protocols. Particular attention was given to the DNP3 and IEC 61850 protocols and information models.

Enterprise Technologies

This session covered technologies being deployed to ensure interoperability with multiple vendor products and services within an energy provider's enterprise systems. Specific attention was paid to general information technology industry technologies being deployed to facilitate cost effective implementation of advanced utility metering systems that integrate with existing/legacy enterprise information systems.

The Path to Interoperability

Presented by Ron Farquarson

This presentation outlined the typical motivations and benefits for an interoperable smart grid, as well as the potential dangers of interoperability without established architecture to support it. Various models for interoperability related to technology, smart grid, and communications were proposed.

Enterprise Integration: Stream and Event Computing

Presented by Ron Ambrosio

This presentation described various approaches to interoperability, acknowledging that utilities are driving towards a more advance T&D monitoring and control system. High performance stream processing and cyber-physical-business systems are applied to the power grid.

Advanced Metering Infrastructure Integration

Presented by Erich Gunther

This presentation covered a proposed architecture for integrating the meter data management function into existing utility enterprise architecture.

Panel Sessions

Architecture Track

The Architecture track emphasized modeling and design approaches and principles of operation that support large, integrated, complex systems. This included examples of methodologies and tools for developing reasonable designs leading to successful implementations. This track targeted information systems designers and integrators to discuss architecture and modeling concepts, the strong influence of the Internet on future directions, and approaches for distributed control and ensuring security in something so vast as the electric system.

Architecture Track Presentations

Name	Presentations
Toby Considine	download
Joe Hughes	download
Ralph Martinez	download
Scott Neumann	download
David Gagliano	download
Del Hilbur	download
Jeffrey Katz	download
Terry Saxton	download
Todd Pistorese	download
Arup Barat	download
Grant Gilchrist	download
David Cohen	download
Glen Platt	download
Apperson Johnson	download
Patrick Hester	download
Jay Abshier	download
Joe Weiss	download
Adrian Gheorge	download
Darren Highfill	download

Track Leader: Dave Hardin; Invensys

Architectural Concepts

Moderator: Scott Neumann

Systems architecture forms the backbone of modern systems design. Well-developed architectures enable systems to achieve short-term objectives while providing the ability to grow and adapt to changes over time. System evolution is especially important for the electric system due to the long life-cycles required. This session explored architectural concepts that are applicable to large-scale, interoperable system architectures needed for the electric system.

Business Innovation and Service Abstractions

Presented by Toby Considine

True Scalability and interoperability require abstraction and security. Most control systems today expose name/value tag pairs as their interface. This poses two problems. Interaction with exposed tag pairs requires a deep understanding of the underlying systems. Secure interaction with sets of tag pairs can only practically be exposed as monolithic yes/no decisions for the entire set. Service oriented architectures and integrations make possible large-scale interactions. Service discovery enables ad hoc interactions. Services hide implementation details. Service oriented architecture to will enable orchestration of building systems including site-oriented energy generation and storage. New business models will take advantage of these new interactions to drive energy use reduction through innovation.

See Appendix C for the complete paper or download the PDF.

Interoperability: The Key Ingredients

Presented by Joe Hughes

Interoperability requires a variety of key ingredients to be successful in the marketplace. This presentation covered some of the main technical areas that need to be covered to achieve truly interoperable equipment. The main elements include mature open standards as well as "integrated" standards. Ideally these are based on stable international standards that provide stability. Next is the development and active participation in user groups and communities that are able to work out remaining technical issues and develop technical agreements for building components to the open standard. Another main ingredient is the development of tools and software that assist the development community. The tools and software can be particularly helpful with interpreting and initially implementing core elements of the open standards. The development of open source tools and code can also be used. Together these three main areas constitute a "three legged stool" for the development of interoperable equipment and systems. In the power industry there are elements of this three legged stool but more work is needed for the development of next generation energy systems.

See Appendix C for the complete paper or download the PDF.

Interoperable Technology Innovations

Presented by Ralph Martinez

The Modern Grid is about major capability and technology modernization. Modernization goals will require new technological innovations and solutions for a reliable, robust, cost-effective, self-protecting, self-healing, and responsive grid. This presentation addressed the interoperability of existing and emerging technology innovations, for an Integrated Communications System Overlay for the Modern Grid.

INTERNET & IT ARCHITECTURES

Moderator: Toby Considine

The Internet has demonstrated that planet-scale interoperability is achievable. Enterprise IT has adapted these technologies to build secure business services on a global scale. This session discussed how current and emerging Internet and IT architectures and technologies can be applied to the electric system.

Demand Response Business Network Architecture

Presented by Scott Neumann

The Demand Response Business Network (DRBizNet) Architecture is a distributed, internet-based architecture that was designed to facilitate communications and business transactions among a large number of Demand Response (DR) stakeholders. This presentation provided a brief overview of the DRBizNet Architecture.

Service-Oriented Network Architecture

Presented by David Gagliano

Web 2.0 and Service-Oriented Architecture (SOA) deliver greater business agility through the creation of highly distributed composite applications that orchestrate components or sub-systems to form higher-level functional systems or target applications. Composite applications can provide tremendous advantages in terms of flexibility, business agility and productivity.

Service Oriented Network Architecture (SONA) provides an architectural approach for connecting intelligent network services to enterprise applications to deliver superior business solutions. SONA provides a framework for network services to support composite applications, ensuring reliable, scalable, secure, and predictable performance across diverse network environments.

Smart Grid Technology Roles and Integrations with Legacy Systems

Presented by Del Hilber

New utility technologies need to find their place and prove their worth in today's complex power trading and control industry. This presentation discussed the potential roles and integrations these technologies will have with legacy power and trading systems. Presentation points included the need for standardized Web Services, Real-Time data aggregation and interoperability with legacy SCADA and trading systems.

Internet and IT Architectures

Presented by Jeffrey Katz

This presentation briefly discussed the integration aspects of the Intelligent Utility Network. Topics included SCADA connectivity, communications, security, standards, Service Oriented Architecture, Complex Event Processing, time dependent middleware, analytics, distributed intelligence and portals.

INFORMATION MODELING

Moderator: Greg Robinson

It is not sufficient to understand just the syntax or grammar of a common language among disparate suppliers and users of data involved in the utility enterprise. Semantic understanding is also required, where rules govern the definition of things, concepts and their relations to one another. This session explored the semantic aspects of information modeling, where attention was given to key matters such as managing the meaning of data across diverse technologies used in business processes, how to cost effectively leverage industry standard models, and how information modeling bridges the technical connectivity issues with the business organizational issues that must be aligned to achieve interoperation.

The Missing Piece – a Common Standards-Based Model

Presented by Terry Saxton

This presentation addressed how the CIM standards lay the foundation for an enterprise information model as a semantic layer in achieving interoperability. Key aspects were discussed, including the importance of defining standards boundaries at the right level of abstraction to ensure adoption and continued use in the face of changing information infrastructures and systems, how unique business contexts based on country and enterprise practices can be incorporated without over-defining the abstract information model standard, the importance of focusing on interfaces for application of semantic model standards and especially for testing for interoperability and compliance, and the essential role of EPRI in extending the CIM into new areas where interoperability is needed as well in interoperability and compliance testing to ensure products comply with CIM standards. The key role of profiles and messaging standards to establish interface contracts were also explained.

See Appendix C for the complete paper or download the PDF.

The Data Paradox

Presented by Todd Pistorese

Fifteen years ago, customers of Supervisory SCADA and DCS realized they needed a way to store and use the volumes of data that their systems were bringing in. Now, years later, utilities are facing exactly the same issues as a result of advanced metering and intelligent grid initiatives. Advanced metering has further elevated data management requirements by expanding data uses to grid management. To create a path to an intelligent grid, and other advanced system applications down the road, timely reconciliation of meter data, SCADA data, distribution automation data, and essentially all operational data sources is required. It is critical to make this data useable, actionable and accessible to multiple entities internal and external to the utility.

See Appendix C for the complete paper or download the PDF.

Interoperability in the ACCP Reference Implementation

Presented by Arup Barat

The Interoperability Context Setting framework provides a comprehensive set of criteria to evaluate a complex system integration solution such as COMSYStm. This presentation explored each crosscutting issue identified in the framework to address the specific challenges, solutions and level of completeness provided by the ACCP project. Finally, it proposed extensions and modifications to the system as a result of the case study and within the parameters set by the context setting framework.

Harmonizing CIM & IEC 61850

Presented by Grant Gilchrist

This presentation described current efforts to harmonize two increasingly popular information technologies used in power utilities: the IEC 61850 standard for substation communications, and the IEC 61968/61970 Common Information Model standards that are used for exchanging data and configuring information between applications in what is commonly called the “control center”. This presentation is a summary of work being done by members of the IEC interoperability working group (TC57 Working Group 19). The work has been identified by a variety of power system organizations as vital to achieving the seamless exchange of data between the field and enterprise necessary to create many “smart grid” applications.

DISTRIBUTED SYSTEMS

Moderator: David Cohen

Scalability in large automated systems relies on the distribution of control and decision-making. These distributed elements must interact using open and interoperable languages and constructs. This session will discuss modern distributed systems and how they can be effectively applied to create the very-complex, large-scale systems required for the modern electric grid.

The Decentralized Control of Electricity Networks

Presented by Glenn Platt

This presentation reviewed the state of the art in distributed energy control systems-decentralized control techniques that coordinate the actions of devices such as electricity loads or generators. The presentation reviewed two recently proposed control techniques that bring significant advantages over the first-generation distributed energy or demand management systems currently being trialed. It introduced the basic operating principles of these systems, and reviewed the challenges involved in realizing these techniques in practical application.

See Appendix C for the complete paper or download the PDF.

Rational Agents for Decentralized Environments

Presented by Apperson Johnson

Given the emergence of new and varied energy producers, consumers, and combinations thereof, software processes and services that work on our behalf must adopt the qualities of intelligent distributed systems to address challenges including: local control of processes, local ownership of data and balancing of competition and cooperation. Rational agents provide a basis for achieving the robustness and efficiency we seek. Agents can be owned by different organizations, can respect boundaries of authority and proprietary control, and can represent appropriate interests while working in concert with other agents and human operators to achieve common goals. This presented the rationale of the agent communication stack, its relevance to energy grid participants, and outlined an agent architecture, which provides agent behaviors as services, affording integration with existing and future service-oriented architectures.

See Appendix C for the complete paper or download the PDF.

Reliability-Based Methods for Electric System Decision Making

Presented by Patrick Hester

This presentation described a methodology that utilizes reliability-based optimization to solve complex electrical grid usage problems. With electrical power grids, as with many complex systems, complicated decisions must be made at both the local (user) and global (electricity provider) levels; all decision makers have independent, often conflicting, objectives, further complicating the decisions. In order to incorporate both levels of decision making (and resulting interaction effects between the decision makers), a reliability-based optimization approach can be utilized which incorporates local decision makers' preferences by enforcing probabilistic constraints on the overall optimization problem (e.g., sectors A and B need a particular amount of power and each sector has a different criticality level).

See Appendix C for the complete paper or download the PDF.

SECURE SYSTEMS

Moderator: Jay Abshier

The advent of standard, open architecture devices and systems in the automation of Electric Sector operational systems has opened the window for new applications, business functionality and interconnections with facilities and end users that were never before imagined possible. The potential for providing new business services and for customers to more efficiently use those services is almost unlimited. Just as the potential for providing new business services is almost unlimited, the potential for cyber security vulnerabilities is also almost unlimited. This session will discuss the areas of cyber security that must be addressed for the secure implementation of the GridWise architecture framework.

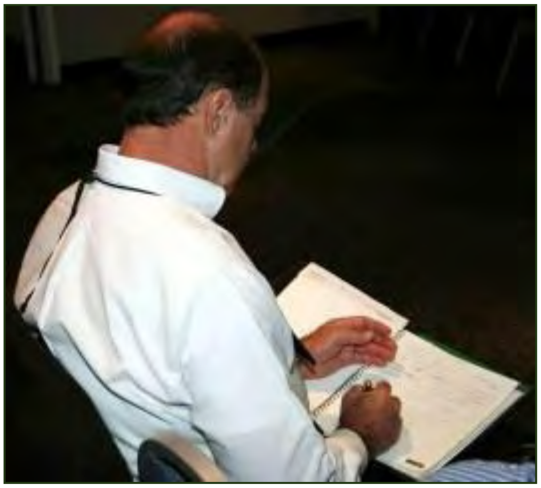
Secure Systems

Presented by Joe Abshier

This presentation was an overview of the Secure Systems session, introducing the various layers of security required for true cyber protection of data.

Interoperability and Security

Presented by Joe Weiss



Most control system communication protocols were developed for interoperability reasons with minimal to no security considerations. Interoperability poses an interesting challenge: interoperability generally "opens" systems while security generally "closes" systems. Consequently, there is a need is to develop methodologies for enabling systems with differing degrees of security (from no security to fully-secured) to seamlessly communicate with each other. The grand challenge is to have interoperability while maintaining adequate security. Both need to be included in the initial design considerations for interoperable systems.

The Advent of the Electricity and Information Paradigm for Critical Electricity Infrastructures

Presented by Adrian Gheorghe

There is no doubt that the growth of power systems and the establishment of the power infrastructure as we know it today, would not have been possible without the extensive use of Information and Communication Systems (ICS). Taking into consideration the capabilities of ICS technologies and the needs of the electric power industry and markets, this trend will continue in the future. There is an urgent need for an understanding of this evolution which, in turn, will help with assessing the positive and negative consequences of this trend.

Security – From Architecture through Policy to Implementation

Presented by Darren Highfill

The Bradley Substation Project reflects the remote side of TVA's End-To-End Integration efforts, with security built-in from the ground up. Technical measures dovetail into corporate policy, and empower a system-wide architecture that is changing the way TVA does business. The new paradigm also brings to light new challenges, illustrating opportunities for utilities to drive the market in the direction they want to go rather than being led by the nose to narrow and shallow options. As we have seen in other aspects of engineering, interoperability shows up at the core of these challenges. Combined with the new cyber threat, the future presents us with a call to arms. TVA's efforts provide the broader community with a wealth of real-world experience from which we may all learn and build. This presentation shows us what we can do when we set our minds to it, and invites dialog about where to go from here.

BUSINESS TRACK

The growth and connectivity of automation across organizations is revealing new business opportunities that depend on interoperability. The Business track emphasized issues and directions emerging from the smart grid relevant to planning and managing business and policy objectives. Specifically, the implications of interoperation between elements of the electric system, or the lack of them, were discussed as they relate to policy, regulation, and business strategies and decisions.

BUSINESS TRACK PRESENTATIONS

Name	Presentations
Don Von Dollen	download
Mary Ann Piette	download
Ross Guttromson	download
Brian Golden	download
Thomas Yeh	download
Conrad Eustis	download
Will McNamara	download
Alison Silverstein	download
Mary Beth Tighe	download
Cindy McGill	download
Kelly McNair	download
Ali Ipakchi	download
Marco Janssen	download

TRACK LEADER: THOMAS YEH; ENNOVATION GROUP

NEW BUSINESS CONCEPTS

Moderator: Philip Bane

The continuing growth in the activities associated with upgrading the nation's electric systems and the increasing deployment of smart grid devices are expected to create many new and exciting prospects for businesses large and small. This Panel session presented examples of new pricing and system concepts that will emerge from wide scale adoption of interoperability. Specifically, concepts in retail market pricing, automated demand-response and a prototype of a ‘perfect power system’ were introduced.

The IIT Perfect Power Prototype

Presented by Don Von Dollen

In 2006, the Galvin Electricity Initiative in collaboration with the Illinois Institute of Technology (IIT), Exelon, Endurant Energy and EPRI initiated the design of a microgrid prototype, based on Perfect Power principles, to serve the entire IIT Campus. This presentation outlined the results of the design study and the associated cost/benefit analysis that is now leading to implementation of the microgrid design by IIT and Exelon for the joint benefit of the university and the grid.

See Appendix C for the complete paper or download the PDF.

Implementation of Automated Demand Response

Presented by Mary Ann Piette

This presentation outlined the business services vision and an open standards based approach to embed DR automation clients in building control systems. Opportunities to require an automation standard for DR communications into building codes for new commercial buildings was also discussed. The standard is intended to lower deployment costs for automated demand response capabilities in the buildings stock. Similar strategies for automation in industrial controls were also presented. This strategy builds on the California’s efforts to develop a common information system for automated programmable communicating thermostats. The benefits of interoperability were outlined to support the business vision.

See Appendix C for the complete paper or download the PDF.

Optimizing Retail Contracts for Electricity Markets

Presented by Ross Guttromson

This presentation posed the questions, “Given several types of markets that can be offered to retail electricity customers, what is the optimal combination that should be offered”? In the Olympic Peninsula Testbed Demonstration, three principle market types were tested: a fixed price contract, a time of use contract, and a real time price contract. Each of these markets offered different benefits to the customers and the utility. Using data obtained from this demonstration over a one year period, a basis for utilities to identify an optimal contract mix which meets their objectives was formulated. The presentation summarized the data gathered and results formulated from the demonstration project.

See Appendix C for the complete paper or download the PDF.

Business Opportunities

Moderator: Allan Schurr

New and expanding opportunities are created when interoperability becomes an enabler for the adoption of new business models. At the same time interoperability will also impact existing business models through competitive pressure and obsolescent. This Panel session presented examples of new product strategies and ways of doing business in a market place where interoperability is still a nascent concept but could gain rapid growth given the pressure to renew the nation's electric power system. Chris Hickman and Sunil Cherian joined Brain Golden in the interactive panel discussion.

Interoperability & New Business Opportunities

Presented by Brian Golden

This presentation introduced the opportunities for interoperability between isolated solar communities and utilities without significant investment by leveraging existing investments to produce operational demand response.

Managing Business Constraints

Moderator: Michael Burr

The management of the electric power system is influenced by large number of stakeholders with a century of legacy. Companies interested in providing smart grid solutions to foster interoperation between elements of the electric system must satisfy the business and policy objectives. These constraints make it difficult to offer new customer services made possible by an interoperable electric system. This Panel will present examples of planning and execution of smart grid projects responding to existing and new business constraints. Specifically, business issues around regulatory implication of a utility's energy efficiency project, the interoperable approach and smart grid appliances, and the constraints around integrating generation and demand resources will be introduced.

Interoperability Challenges for Demand-Side Resources

Presented by Thomas Yeh

Interoperability is a concept that few executives would argue with but yet is fraught with real-world constraints. An example case is the integration of central generation capacity resources with demand-side capacity resources. Given the growing importance of managing demand to the health of the electric power system in the face of continuing load growth, and the need to integrate demand management into the next generation power system design, interoperability framework can play an important role so demand-side capacity can be readily called upon by the Utilities and ISOs as a critical system resource similar to central generation plants.

Appliance Interface for Grid Responses

Presented by Conrad Eustis, Donald Hammerstrom & Gale Horst

A successful, rapid integration of technologies from three different companies was achieved as part of the Grid Friendly™ Appliance Project. Therein, a simple but effective interface was

defined between a vendor's commercial energy management system control module, an experimental electronic sensor and controller, and a smart appliance. The interface permitted each entity to use its preferred, proprietary communications up to the interface without divulging any protected or sensitive attributes of the entity's hardware, software, or communication protocols. Those who participated in this integration effort recognize the potential value of the interface as an interoperability model, which could be expanded and extended with participation and buy-in from a larger community of stakeholders. The result could become a universal interface for the communication of demand response objectives to appliances and other small loads. The presentation focused on the business and marketing challenges of the project.

See Appendix C for the complete paper or download the PDF.

Regulatory Implications Faced by Duke Energy's Utility of the Future Project

Presented by Will McNamara

Charlotte, NC-based Duke Energy serves approximately 3.9 million customers in five states: North Carolina, South Carolina, Ohio, Indiana, and Kentucky. Established in 1927, KEMA Inc. is an international, expertise-based energy solutions firm providing technical and management consulting, systems integration and training services to more than 500 electric industry clients in 70 countries. There are a number of regulatory challenges that Duke Energy presently faces related to its Utility of the Future project, not the least of which is the fact that it must eventually submit regulatory filings for the project to five different public utility commissions.

Smart Grid Interop Policies

Moderator: Steve Hauser

The federal & state legislatures are moving forward to develop policies that encourage steps to advancing the smart grid. Similarly, utility regulators are tackling smart grid proposals from service providers and consumers. Embedded in these policy statements and legislation are statements that can help or hinder interoperation. This session reviewed activity underway, discuss aspects of policy making that can influence interoperability, and provided examples of decisions that advanced or impeded the ability of multiple products, services, and providers to integrate and interact effectively.

A Taxonomy of Energy Policies Affecting the Smart Grid

Presented by Alison Silverstein

This presentation described four energy policies that could be used to enhance or expedite adoption of target technologies or products including reducing costs for manufacturers and sellers, reducing costs for customers, growing the market, or removing obstacles.

Innovations in the Energy Equation Shape Future Transmission Infrastructure

Presented by Mary Beth Tighe

This presentation outlined the Federal Energy Regulatory Commission (FERC) activities related to demand response and grid reliability.

UTILITY BUSINESS IMPACTS

Moderator: Joseph (Joe) Bucciero

The issues and directions emerging from adoption of the smart grid will impact utilities in a multitude of ways. In addition to tackling new technical and operational concerns, utilities must face a wide array of business challenges and capitalize on new opportunities. This Panel session presented examples of specific challenges facing today's utilities and how interoperability could actually enhance utility's business.

Utility Enterprise Information Management Strategies

Presented by Kelly McNair

This presentation discussed how two utilities, Oncor Electric Delivery and San Diego Gas & Electric (SDG&E), are addressing information management challenges through their Enterprise Information Management (EIM) initiatives. EIM frameworks and strategies provide a clear roadmap for utilities to establish the necessary governance and technology solutions. EIM is not only complementary to Service-Oriented Architecture, but is also required for businesses to drive and enable the convergence of operational technology (OT) and information technology (IT), which are key parts for the ultimate realization of a Smart Grid. This presentation shared experiences of how these utilities have embarked on the journey of EIM to better prepare the enterprise business and IT for the upcoming business transformation programs such as Enterprise Application Integration, Advanced Metering Infrastructure, Smart Grid, and Asset Management. Co-authors: Kamal Parekh of San Diego Gas & Electric, Joe Zhou of Xtensible Solutions, Greg Robinson of Xtensible Solutions.

See Appendix C for the complete paper or download the PDF.

Challenges and Opportunities with the Smart Grid

Presented by Ali Ipakchi

This presentation described information management and systems integration requirements for a broad-base implementation of Smart Grid applications. It provided representative examples, discusses existing challenges, and presented a general approach for enterprise level implementation of information systems in support of Smart Grid initiatives.

See Appendix C for the complete paper or download the PDF.

Interoperability Enhances Utility Business

Presented by Marco Janssen

While most utilities recognize the possible advantages of interoperability and networking applications, many of the applications used today are run in so called information silos, where each application has its own dedicated communication path and/or protocol. Due to the deregulation of the power industry utilities are now forced to operate much closer to the operating limits of their high voltage network and this has led to a search for solutions that allow responses in a much more dynamic way.

See Appendix C for the complete paper or download the PDF.

TECHNOLOGY TRACK

The Technology track panel sessions emphasized how interoperability concepts and architecture can be implemented through the application of specific standards, technologies, devices, and best practices. The sessions included case studies that illustrate how interoperability was achieved in areas of the electric system through the application of technologies, standards, and best practices.

TECHNOLOGY TRACK PRESENTATIONS

Name	Presentations
Jim Luth	download
Gary McNaughton	download
Frances Cleveland	download
Wei Hong	download
Jake Rasweiler	download
James Pace	download
Brent Hodges	download
Piyush Maheshwari	download
Mark Osborn	download
Paul Hines	download
Tim Schoechle	download
Alan Johnston	download
Jeremy J. Roberts	download
Rik Drummond	download
Tony Bamonti	download
Andrea Mammoli	download
Jim Lee	download
Ed Koch	download

TRACK LEADER: RON AMBROSIO; IBM T.J. WATSON RESEARCH CENTER

STANDARDS BENEFITS

Moderator: Frances Cleveland

The foundation of interoperability is based upon the unambiguous agreement of the parties involved in a transaction. Being able to cite a standard or multiple standards for coverage of the technical, informational, and organizational aspects of interoperability can significantly simplify the effort to reach agreement. In addition, products can be built and deployed with greater ease of integration and maintenance. These and other benefits of standards were explored in this panel session with reference to specific standards efforts across the electricity stakeholder community.

OPC Unified Architecture: Product Level Interoperability

Presented by Jim Luth

The technical interoperability challenges faced in modernizing the nation's grid as outlined in the GWAC Interop Framework will require new approaches and new technology. The high level of semantic and physical interoperability desired will not easily be accomplished using existing standards and methodologies. This presentation describes how a brand new standard from the OPC Foundation, the Unified Architecture, was designed to address the future of interoperability needs of the industrial automation world and how it could be put to task in the grid application space and aid in the solution to many of the difficult cross-cutting issues identified by GridWise. OPC Unified Architecture (UA) embraces the latest web services technologies providing the highest levels of security and platform tool support, but goes well beyond web services by providing a set of standard services for exposing any rich data as well as its corresponding metadata. The data and metadata is logically organized as a collection of nodes connected by references (a network-model database). The standardized UA services are used to discover, browse and query, read, write and subscribe to the data. UA's ability to expose, with full fidelity, arbitrarily complex organizations of data, make it ideally suited for combining with other high-level information model standards such as the IEC 61xxx CIM Model. Doing so, UA bridges the gap between today's existing low level wire protocol and the information model standards, allowing certifiable application to application interoperability to be achieved.

Multi-Speak and CIM – A Roadmap to Interoperability

Presented by Gary McNaughton

NRECA's MultiSpeak® specification is an industry-wide standard that facilitates interoperability of diverse business and automation applications used in electric distribution utilities. Interoperable MultiSpeak-enabled applications are already in place in numerous electric utilities and permit integrated operation of previously stand-alone systems. MultiSpeak provides similar capabilities to those included in the IEC 61968 distribution extensions to the Common Information Model (CIM). The presentation discussed how MultiSpeak implements key portions of the GridWise Interoperability Framework and illustrates such support by identifying examples of use cases where the most recent version of the MultiSpeak specification can already address the need for significant interoperability among systems. Such examples illustrate how the exchange of information using MultiSpeak has created the potential for utilities to perform services that were previously impossible.

See Appendix C for the complete paper or download the PDF.

Interoperability Benefits of IEC Standards for DER Management

Presented by Frances Cleveland

Europeans are moving very rapidly toward increased interconnection of Distributed Energy Resources (DER) generation and storage, driven largely by the European mandates for reducing carbon dioxide and other pollutants, while US efforts are slowly gathering momentum as many States are also mandating the use of more renewable energy sources. DER generation and storage can provide renewable energy, increased energy efficiency, and increased power system reliability. However, the effective management of widespread DER generation and storage plants requires significant amounts of information from widely distributed locations, from diverse types of DER equipment and plants, and from many different types of utility customers. Increasingly, European utilities, DER vendors, and DER implementers are looking to the IEC 61850 standards for DER to provide the interoperability they need at the lowest cost. They perceive many benefits, but many challenges also remain, including completion of the IEC 61850 standards for DER and the determination of how these DER standards interrelate with other IEC standards, such as the CIM.

COMMUNICATIONS NETWORKING

Moderator: Marco Janssen

Several alternatives exist for creating communications networks that support the ability to connect multiple devices and systems in the electric system. The session explored some of these alternatives and their progress in providing an environment that improves system integration and interoperation.

Pervasive Grid Interoperability with Internet Protocols

Presented by Wei Hong

For wide-scale adoption in grid applications, IP itself must cross a new scale barrier: it must run on the tiny embedded systems that will pervade the grid. In particular, flexible spatial reach is greatly enhanced by wireless connectivity. This may be WiFi or Cellular for larger powered devices, or it may be the more resource-efficient IEEE 802.15.4 radio standard when connecting devices with limited memory or power supplies (e.g. solar), within the grid or customer premises. Building on the increasing adoption of 802.15.4 radios for wireless sensing and control, Arch Rock and others have enabled “E+I” Network and Protocol Interoperability by developing a standard IP adaptation layer called 6LoWPAN, allowing full IPv6 networking to extend to these wireless embedded systems. This presentation described the 6LoWPAN technology and its applicability to the Power Grid.

Smart Wireless Communications for Smart Devices

Presented by Jake Rasweiler

This presentation identified the interoperability issues for B2B Wireless Communication Infrastructure for Utility's Smart Grid deployments and also identified the key technical and business barriers by relating aspects associated with interoperability benefits, principles, and the GridWise context-setting framework.

See Appendix C for the complete paper or download the PDF.

Interoperability, an IP-Centric Approach

Presented by James Pace

The Gridwise Interoperability Checklist is a tool to assist regulatory and utility decision-makers in evaluating capital asset investments or new information technologies with the aim of ensuring interoperability as a core value. This presentation analyzed, point-by-point, each tenet of the checklist in the context of deploying core "smart energy" and AMI networks. It analyzed current approaches to ensuring interoperability such as external interfaces (i.e., APIs) and drill downed into the core of the network, positing that each tier or device in a network should be IP-enabled. IP technologies have passed the test of time, scale, scope, leverage, and security and are key to ensuring interoperability and protection of investment.

Zigbee Powers Energy Efficiency

Presented by Brent Hodges

Within the Electric Utility market, ZigBee is used as a wireless standard to connect the electric meter or other Utility owned device to consumer owned devices in the home, forming what is know as the HAN, or Home Area Network. Devices on the HAN, receive messages from the utility by having ZigBee technology in both the consumer owned device [e.g. the thermostat] and in the utility owned device such as the electric meter. This presentation provided an overview of the Zigbee technology as an example of network interoperability.

UTILITY OPERATIONS

Moderator: Russell Robertson

This session reviewed the importance of interoperability to support important electric utility applications in the operational environment. Examples of these applications were given, stressing the points in the system where components interface, and the importance of defining interfaces and making technology choices that improve interoperability.

Role of Interoperability in the Indian Power Sector

Presented by Piyush Maheshwari

Economical growth in India has led to a considerable growth in its power sector. Issues related to system expansion, restructured environment, and changing regulatory framework demand changes in planning and operating strategies and in the design of system architecture for future needs. This presentation explored the role of interoperability in the Indian power system context. Four levels of interoperability viz., organizational interoperability, application interoperability, information interoperability and technical interoperability were discussed with the help of typical scenarios. It is observed that interoperability among various systems of the power grid is crucial for achieving the benefits of open architecture based future control centers.

See Appendix C for the complete paper or download the PDF.

Virtual Peaking Networks

Presented by Mark Osborn

Dispatchable Standby Generation first supplies power to its designed load at the customer's facility then any excess power flows into the PGE system. To the PGE system grid, this appears as a drop in load and an increase in supply because most sites have excess generator capacity. All relay protection equipment necessary for a safe interconnection to the distribution grid is provided. PGE's System Control Center monitors the units 24/7 and has the option to run the generators up to 400 hours annually. To operate and manage these remote resources requires four things: a high-speed secure communications network; upgraded generator controls; intelligent metering; and a centralized control center to coordinate dispatch & maintenance of generators. PGE developed a system called "GenOnSys" that graphically manages the aggregation, dispatching, alarming, monitoring & analysis of valuable engine, generator and facility metering & power quality data. The system also monitors/dispatches other forms of distributed generation on PGE's system; including, microturbines, solar arrays and a small biogas facility. In the near future, this system can manage solar roof-top aggregation; potentially providing the next wave of grid support for seasonal peaking on the PGE system.

Integrated, Agent-Based, Real-time Control Systems for T&D Networks

Presented by Paul Hines & Charles Vartanian

Centralized control systems can be easier to design and generally conform to utility industry practices, but have disadvantages in terms of actuation speed and limited robustness to failures. Interoperability among devices and across systems will facilitate decentralized decision-making systems that can react quickly to local problems and, when well designed, are more resilient to failures. This presentation described a conceptual design for the integrated, real-time control of both transmission and distribution systems. The design uses intelligent control agents located at nodes in the grid. To illustrate the utility of decentralized, agent-based, real-time control the presentation described two agent-based control algorithms, one designed to mitigate the effects of cascading failures in the transmission system and the other designed to improve distribution circuit performance. After describing the proposed design concepts and presenting some example results, the presentation described some information technology advances that have the potential to enable an interoperable network of software agents with real-time control capabilities for both transmission and distribution.

See Appendix C for the complete paper or download the PDF.

STANDARDS ADOPTION

Moderator: Tim Schoechle

Writing standards is rarely easy, but seeing standards adopted is more difficult. This session reviewed successes and failures in making standards that lead to their adoption or abandonment. Representatives from different industry standards efforts and trade groups were represented as part of the panel session.

Getting the Technology Solutions into the Marketplace

Presented by Tim Schoechle

The standards adoption process begins with discussion and consensus-building among technical experts around a specific topic of mutual interest. The goal is to reach agreement on a technical specification that can win broad support among participants. These discussions may take place under a broad array of different organizational sponsorship (e.g., trade associations, professional societies, national committees, international committees, industry forums or consortia, etc.) but the key elements of the standardization process include openness, due process, and balanced participation. Such elements are important because the adoption and deployment of technical standards in the marketplace, being largely voluntary, depends on the perception of their technical quality, fairness, and legitimacy. The world of standardization divides roughly into two kinds of bodies: 1) the older traditional "formal" national, regional, and international standards bodies (e.g., ISO, IEC, ITU, CEN, CENELEC, ANSI, DIN, BSI, etc.), and 2) the newer emerging "informal" industry-focused consortia. Although initially competing and differing widely in their practices and procedures, in recent years these bodies are evolving complementary roles and increasing collaboration. They both seem to offer certain advantages and benefits that together can help achieve the basic role of standards--facilitation of trade and commerce--and thus serve consumers, industry, and government.

The OpenO&M™ Initiative Revolutionizes Future Electrical Systems

Presented by Alan Johnston

This presentation described the OpenO&M Initiative (which is a collaborative effort between MIMOSA, OPC, OAGi, WBF/B2MML and ISA) and the application of the respective technology to the current and future electrical systems. This is a true example of information modeling at its finest, with widespread standards harmonization and true enterprise integration in both the private and public sectors. This collaboration has begun to streamline and serve as a solid infrastructure for numerous asset-centric industries inclusive of oil and gas, aerospace and defense and process manufacturing. This presentation discussed the mapping and potential cross industry synergies between the electrical systems of the future and other key industry groups, including but not limited to those related to integrated energy management. The OpenO&M Initiative seeks to help suppliers developing products and solutions that address the interoperability requirements of both the electric industry and many related domains in a holistic and pragmatic manner.

Protocols from Generation to Consumption – and Back

Presented by Jeremy J. Roberts

With so many standards available in the world, which one is most appropriate for a given application? Most standards are specific to one or only a few vertical markets -- providing varying degrees of interoperability within constrained industry sectors but what happens when your needs expand beyond the reach of a given protocol? For example, how many protocols must be chosen to implement communications between an electric utility's billing system, their distribution system, general street-lighting control/monitoring, and even a customer's electric meter? And will yet another protocol be needed to branch into the premise to provide value-added services? What about the devices within a premise (be it a home or an office building)? Heating, lighting, security, elevators, safety, and appliances -- do all of these systems need their own protocols? How will you tie them together for seamless integration and added value? Would such an attempt fail? This brief overview attempted to whet the palate for conquering what otherwise may be a very daunting task.

Creating a Marketplace for Implementation Ready Interoperable Products

Presented by Rik Drummond

This presentation showed the different outcomes of interoperability certification programs instituted for three well known industry standards; why some became heavily used and others did not even though all three standards were well designed to address business needs.

See Appendix C for the complete paper or download the PDF.

DEMAND RESPONSE

Moderator: Mary Beth Tighe

Arguably the first killer application that is bringing attention to the smart grid effort is demand response. This session looked at demand response programs, pilots, and approaches that are being taken. The importance of defining interfaces for the demand response components that support interoperation and reduce system integration were also highlighted. The challenges being faced in this area were also discussed.

Residential Demand-Side Energy Management

Presented by Tony Bamonti

This presentation outlined the key requirements for a residential Energy Management System that will encourage and engage consumers in participation in demand response programs. The discussion touched on the types of systems that are required to provide utilities' effective management, forecasting and shed of residential energy demand, while providing valuable tools for customers to manage their personal electrical costs and consumption.

The Interoperability Potential of UNM Campus

Presented by Andrea Mammoli

This presentation analyzed the electrical energy usage of the UNM campus for the purpose of estimating the potential of the campus to respond to grid status information, by altering its energy consumption characteristics. Possible response (reactive and predictive) strategies were discussed in light of inputs from various IT systems, such as scheduling databases, weather forecasts, and utility data. The discussion concluded with a summary of the project teams' estimate of a potential 3 MW response, with more if several IT and physical systems were put in place.

See Appendix C for the complete paper or download the PDF.

Building Dynamics and Demand Response

Presented by Jim Lee

Building automation systems can provide a substantial amount of data about a building HVAC system's actual response to a DR event. The efficacy of a DR control sequence can be assessed by analyzing HVAC trend data and electricity demand data collected during simulated or real DR events. If necessary, adjustments can be made to the DR control sequence and to HVAC control loops in order to improve the HVAC system's reaction to the DR event. The data can also be used to create a simple model for predicting how the power consumed by the HVAC system will change during a hypothetical DR event.

Interoperable Automated DR Infrastructure

Presented by Ed Koch

This presentation described the concept for and lessons from the development and field testing of an open, interoperable communications infrastructure to support automating demand response (DR). Automating DR allows greater levels of participation and improved reliability and repeatability of the demand response and customer facilities. The presentation focused on the Demand Response Automation Server (DRAS) which has been developed over many years of research by the Demand Response Research Center (DRRC) of Lawrence Berkeley National Laboratory (LBNL). The DRAS has been proven effective in both pilot and commercial deployments of DR programs for a number of years by the DRRC and all the major Utilities in California. It has been designed to generate, manage, and track DR signals between Utilities and ISOs to aggregators and end-use customers and their control systems. This presentation described the various technical aspects of the DRAS including its interfaces and major modes of operation. Use cases were presented that show the role of the DRAS in automating various aspects of DR programs. This includes how the DRAS supports automating such Utility/Customer interactions as automated DR event handling and automated DR bidding. Finally a synopsis was given of the DRAS standardization effort that has been initiated by the DRRC and is currently supported by all the major Utilities in California as well as various other organizations nationwide.

See Appendix C for the complete paper or download the PDF.

Roundtable Sessions

Introduction

During the Grid-Interop Forum, conference attendees were able to participate in one of six breakout groups focused on developing actionable items to advance the state of interoperability of the electric grid with various user segments. The Action Roundtables were conducted in two segments over two days and produced work output that identified the opportunities for action as well as providing an initial plan for action. In each group, expert champions representing the various user segments provided context setting information to help participants make plans for collaboration and action.

Areas where the participants were willing to take the action were identified and each group outlined the assistance needed from government or industry, other than money, to help facilitate the actions identified.

The following is a summary of the outputs of the various Action Roundtable sessions. More detailed notes are included in the appendix of this document.

Appliance to Grid

Moderator: Alison Silverstein; Independent Consultant and GWAC Member

The aspects of interoperability discussed by champions in the utility to appliance interface domain focused on determining the building blocks needed for early technical analysis and business case development for appliance to grid interoperability. Discussions of what success would look like, the types of communication needed for consumers, the technologies available, and the technology/policy issues surrounding the appliance to grid interface were also part of the discussion.

Key Actions:

- Identify the stakeholder groups interested in smart grid appliances
- Define a core set of capabilities to be implemented in all smart appliances
- Conduct a consumer research project to formulate plans to encourage consumer demand

Assignments:

Action	Responsibility	Timeline
Survey stakeholders		
Define core capabilities		
Conduct consumer research project		

Participants: Alison Silverstein, Marco Janssen, others

Government/Industry Assistance:

- Utilities – leveraging of communication systems and non-price related incentives to encourage smart grid solutions.
- Industry - leverage communication system and internet solutions before utility infrastructure becomes available, articulate core capabilities for every appliance, focus on flexible interfaces and minimum solution implementation.

Building to Grid

Moderator: Jack Mc Gowan; Energy Control, Inc. and GWAC Chair

Expert champions in the utility to building interface domain discussed building protocols, ongoing demand response projects, and various areas of standardization. The group also discussed the need for interoperability within buildings and how this might interface with green building rating systems such as LEED.

Key Actions:

- Define short list of key buildings organizations and a plan for reaching out to them
- Organize a Building to Grid Summit at the ASHRAE/ARI AHR meeting
- Define LEED points for demand response

Assignments:

Action	Responsibility	Timeline
Stakeholder outreach	Toby Considine	12/2007
Building to Grid Summit	Jack Mc Gowan	1/2008
LEED points for demand response	Ed Koch	12/2007

Participants: Jack Mc Gowan, Ron Ambrosio, others

Government/Industry Assistance:

- Government – definition of building codes and establishment requirements for building to grid interactions
- Industry - agreement from vendor community to invest some level of effort in working toward uniform building to grid requirements

Home to Grid

Moderator: Erich Gunther; EnerNex Corporation and GWAC Member

Champions in the utility to consumer interface domain – namely those participating in the OpenHAN industry effort – discussed the devices that straddle the utility to home network boundary as well as the information models, messages and standards necessary to interact with end-use devices.

Key Actions:

- Enhance collaboration between ISO WG1 and OpenHAN
- Propose rate structure model harmonization
- Develop economic model
- Expand stakeholder community

Assignments:

Action	Responsibility	Timeline
Collaboration	Tim Schoechle, Erich Gunther	now
Rate structure	Joe Hughes	12/2007
Economic model	Steve Widergren (in absentia)	Q1/2008
Expand stakeholders	Steve Hauser, Dan Delury (in absentia)	Q1/2008

PARTICIPANTS: ERICH GUNTHER, RUSSELL ROBERTSON, OTHERS

Government/Industry Assistance:

- Government - consistent set of security policies
- Government - single point of leadership on smart grid issues
- Government - consistent incentives from policy makers

INDUSTRIAL TO GRID

Moderator: David Hardin; Invensys and GWAC Member

Discussions by champions from the large and diverse industrial sector focused on ways to raise industry awareness of economic opportunities based on peak demand, plans for soliciting case studies from utilities, and methods for defining standard smart grid interconnect for dispatchable/distributed generation.

Key Actions:

- Make industry aware of economic opportunities based on peak demand
- Solicit case studies from industry
- Define standard smart grid interconnect interface for dispatchable/distributed generation

Assignments:

Action	Responsibility	Timeline
Industrial/Utility Consortia	Dave Hardin, Thomas Yeh, Tim Baker	4/2008
Case studies	Paul Pruschki, Jeff Harrell, Subodb Nayar, Jim Baker	1/2008
Standard interconnect proposal	Bob Crigler, Jim Luth, Apperson Johnson	

PARTICIPANTS: DAVE HARDIN, APPERSON JOHNSON, BOB CRIGLER, DAVE HARDIN, JAMES BAKER, JEFF HARRELL, JIM LUTH, MARK OSBORN, MIKE PEARMAN, PAUL PRUSCHKI, & THOMAS YEH

Government/Industry Assistance:

- Government – Small Business Innovation Research/Technology Transfer Research grants for industry to grid interoperability

CONSUMER SIDE HARMONIZATION

Moderator: Joe Bucciero

Discussions by expert champions from the industrial, building, and home automation sectors focused on the harmonization of standards. Various educational and communication efforts along with ongoing demonstration projects were also discussed as ways to help facilitate standards harmonization.

Key Actions:

- Work through GWAC, EPRI, ASHRAE, OpenAMI and national labs to harmonize standards, functional data objects, and models
- Publish white papers focused on communicating standards harmonization results
- Publish newsletter on visible website or SharePoint
- Conduct ongoing demonstrations to present case studies

Assignments:

Action	Responsibility	Timeline
Work through industry groups and national labs to develop common data models and roadmap	Joe Bucciero, Paul Nagel, Angela Chang	Initial contact with identified players by May 2008
Raise awareness through industry papers and workshops	Tom Burke, Jim Lee,	Papers prepared for Connectivity Week
Define industry-wide visible site or SharePoint Site for publishing a newsletter and sharing information	DOE, Tom Burke, Paul Wang	1Q2008
Urge vendors to publish standards adoption	DOE, Paul Nagel, Mike Burns	May 2008
Urge SCE to present demonstration results in May 2008	Terry Mohn, Joe Bucciero	May 2008

Government/Industry Assistance:

- Government – heightened awareness for standards harmonization
- Industry – distribution of successful case studies
- Government - GridWise framework and EPRI IntelliGrid convergence at Connectivity Week
- Government/Industry - GridWise Alliance encouragement to drive industry efforts towards standards harmonization

ENTERPRISE TO GRID

Moderator: Rik Drummond; Drummond Group and GWAC Member

Session participants focused on the creation of a top to bottom documented process for establishing smart grid interoperability. The identification of related tools and methodologies, awareness of other related activities, collaboration across multiple relevant activities, and system of system interaction were all identified as playing major roles in the development of the process.

Key Actions

- Form core team to create project plan for documented interoperability process

Assignments:

Action	Responsibility	Timeline
Create project plan	Ali Ipakchi, Wayne Loncore, Frances Cleveland, Rik Drummond, Terry Saxton	12/2007

PARTICIPANTS: RIK DRUMMOND, ALLAN JOHNSTON, BOB SAINT, GARY MCNAUGHTON, GREG ROBINSON, WAYNE LONCORE, TERRY SAXTON, JOE WEISS, FRANCES CLEVELAND, SCOTT NEUMAN, ANDREAS TOLK, FRED ELMENDORF, ALI IPAKCHI, RUTH TAYLOR, RENE MIDENCE, & DILEEP RUDRAN

Government/Industry Assistance:

- Government - formal recognition of process documentation if appropriate
- Government/Industry - marketing/education support for documentation

Appendix A. Agenda

Wednesday, November 7, 2007

	Architecture Foundations	Business Foundations	Technology Foundations
12:00		Registration Opens	
13:30	Architecture, Model Concepts	Hitchhiker's Guide to the Interoperability Framework	Field & Device Technologies
14:45		Break	
15:15	Methods & Tools	Decision Maker's Checklists	Enterprise Technologies
16:30		Break	
17:00		Interoperability Survey	
18:00		Mayor of Albuquerque Welcome	
18:10-19:00		Networking Reception	

Thursday, November 8, 2007

	Architecture Track		Business Track		Technology Track	
8:00			Registration & Continental Breakfast			
8:45			Grid-Interop Keynotes Interoperability Mega Panel			
10:30			Break			
11:00	Architectural Concepts		New Business Concepts		Standards Benefits	
12:15			Lunch			
13:30	Internet & IT Architectures		Business Opportunities		Communications Networking	
14:45			Break			
15:15	Appliance to Grid	Building to Grid	Home to Grid	Industrial to Grid	Consumer Side Harmonization	Enterprise to Grid

16:30	Break		
17:00	Information Modeling	Managing Business Constraints	Utility Operations
18:15	Expo & Networking		
19:00	Free time		
20:00-22:00	Dinner		

FRIDAY, NOVEMBER 9, 2007

	Architecture Track		Business Track		Technology Track	
7:30	Registration & Continental Breakfast					
8:00	Distributed Systems		Smart Grid Interop Policies		Standards Adoption	
9:15	Break					
9:45	Appliance to Grid	Building to Grid	Home to Grid	Industrial to Grid	Consumer Side Harmonization	Enterprise to Grid
11:00	Break					
11:30	Secure Systems		Utility Business Impacts		Demand Response	
12:45	Expo & Networking					
13:00	Lunch & Closing Remarks					
14:30-15:00	Expo & Networking					

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Appendix C: Papers

Papers

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Design and Implementation of an Open, Interoperable Automated Demand Response Infrastructure

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Keywords: Demand response, automation, commercial buildings, peak demand

Abstract

This paper describes the concept for and lessons from the development and field-testing of an open, interoperable communications infrastructure to support automating demand response (DR). Automating DR allows greater levels of participation and improved reliability and repeatability of the demand response and customer facilities. Automated DR systems have been deployed for critical peak pricing and demand bidding and are being designed for real time pricing. The system is designed to generate, manage, and track DR signals between utilities and Independent System Operators (ISOs) to aggregators and end-use customers and their control systems.

1. INTRODUCTION

California utilities have been exploring the use of critical peak pricing (CPP) and other DR pricing and program strategies to help reduce peak day summer time electric loads. Recent experience with DR has shown that customers have limited knowledge of how to operate their facilities to reduce their electricity costs under CPP or in a DR Program [1]. While the lack of knowledge about how to develop and implement DR control strategies is a barrier to participation in DR programs like CPP, another barrier is the lack of automation of DR systems. Most DR activities are manual and require building operations staff to first receive emails, phone calls, and pager signals, and second, to act on these signals to execute DR strategies.

The various levels of DR automation can be defined as follows. **Manual Demand Response** involves a labor-intensive approach such as manually turning off or changing comfort set points at each equipment switch or controller. **Semi-Automated Demand Response** involves a pre-programmed demand response strategy initiated by a person via centralized control system. **Fully-Automated Demand Response** does not involve human intervention, but is initiated at a home, building, or facility through receipt of an external communications signal. The receipt of the external signal initiates pre-programmed demand response strategies. The authors refer to this as Auto-DR. One important concept in Auto-DR is that a homeowner or facility manager should be able to "opt out" or "override" a DR event if the event comes at time when the reduction in end-use services is not acceptable.

From the customer side, modifications to the site's electric load shape can be achieved by modifying end-use loads. Examples of demand response strategies include reducing electric loads by dimming or turning off non-critical lights, changing comfort thermostat set points, or turning off non-critical equipment. These demand response activities are triggered by specific actions set by the electricity service provider, such as dynamic pricing or demand bidding. Many electricity customers have suggested that automation will help them institutionalize their demand response. The alternative is manual demand response -- where building staff receives a signal and manually reduces demand. Lawrence Berkeley National Laboratory (LBNL) research has found that many building energy management and controls systems (EMCS) and related lighting and other controls can be pre-programmed to initiate and manage electric demand response.

This paper provides an overview of the AutoDR field tests and implementation activities from 2003-2007. A companion paper describes the technology in greater detail. This paper focuses on the automation design history and does not cover the shed strategy or shed measurement details which are covered in previous papers [2,3,4,5].

2. TECHNOLOGY HISTORY

The automated demand response project began in 2002 following California's electricity market crisis with the goal of addressing three key research questions. First, is it possible using today's technology to develop a low-cost, fully automated infrastructure to improve DR capability in California? Second, how "ready" are commercial buildings to receive common signals? Third, once a building receives a signal, what type of strategies are available that can be readily automated?

Research planning began in 2002 and a series of field tests and implementation programs were organized to advanced the technology from the initial conceptual design to the status today where it has been designed for use with over 100 facilities over 200 kW.

2.1. 2003: Initial Development and Tests

The 2003 technology development began with the design of a fictitious price signal and automation server that could be represented in XML (Extensible Markup Language) to support interoperable signaling. The automation uses a client server architecture and has been tested with both pull and push communications designs. Five facilities were recruited: 1) a large office, 2) supermarket, 3) pharmaceutical research campus including a cafeteria and a small office, 4) data center/office, and 5) a university campus library. Criteria for recruitment includes evaluating different types of facilities, multiple vendor Energy Information Systems [6], multiple vendor Energy Management and Control systems, multiple technology gateways, difference types of ownership, and a variety of end-use load reduction strategies [2].

All of these sites had participated in DR and had been equipped with new communications and monitoring systems as part of California's Enhanced Automation program [7]. Preparations for the test involved the development of an automation server and the XML software client installations at each of the client sites. The client listens to the signal continuously and replies with the price level. The test resulted in fully automated shedding during two events with an average peak reduction of about 10%.

2.2. 2004: Scaled Up Tests with Relay

The design of the 2004 tests began with the consideration that many facilities did not have EIS and EMCS that could support XML. We reviewed existing technologies and modified the DR automation price server to interoperate with a low-cost Internet relay. The Internet relay is a device with relay contacts that can be actuated remotely over a local or wide area network or the Internet using Internet Protocols (IP). The 2004 technology development and field tests were similar to the 2003 tests in that they were purely fictitious, with no real payment for DR performance. Eighteen sites were recruited to participate in a series of tests. To help in recruiting, the facility managers were offered the assessment of how "ready" their automation systems were to receive common signals for the future's dynamic tariffs and DR program opportunities.

Figure 1 shows the geographic distribution of the participant sites along with the development sites and price-server clients. Many development sites for the XML software client were located outside of California. The price clients listening to the signals could be implemented outside California, as the figure shows. Energy managers out of state can monitor the automation system communications in real time from any web browser.

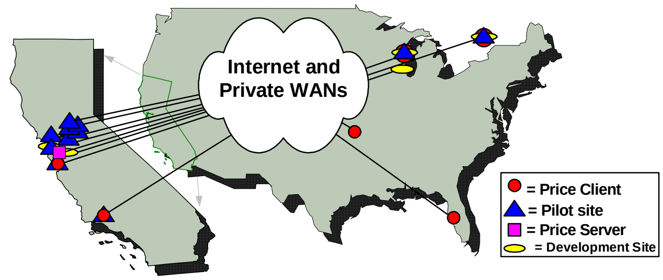


Figure 1. Geographic location of Auto DR facilities, automation clients, and server.

Fifteen facilities participated in the 2004 tests with about half using the XML software client and half using the Internet relay. The average demand reduction for these 15 sites was 0.53 W/ft^2 or about 14% of the whole building electric-peak demand. Table 1 shows an example of how a building would pre-program a response to general DR mode information. A facility manager can decide how to translate the general DR modes into whatever response strategy they choose.

Table 1. Sample DR building control strategies by mode

Building Type	End-Use	Normal	Shed Level 1 Moderate	Shed Level 2 High
Large Office	HVAC	Zones - 72 F	Zones - 76 F	Zones - 78 F
Supermarket	Lighting, Refrig	All On	Lights Down 35%	Anti-Sweats Night Mode

Note: HVAC – Heating, ventilation, and air conditioning

2.3. 2005: Critical Peak Pricing

In 2005 we began our initial collaboration with the Pacific Gas and Electric Company to offer AutoDR as part of the Critical Peak Pricing (CPP) Program. To participate, a site had to be willing to go onto PG&E's CPP tariff. The tariff offers a rate discount during most summer days, but prices increase on CPP days as shown in Figure 2. Fifteen facilities participated in the Automated CPP tests. CPP usually is called 12 times in each summer but because the automation systems took time to install, the tests were not conducted until late in the summer. For the eight sites participated in the fully automated CPP event on September 29th, 2005 the average demand response ranged from 0 to 24% per site for the medium price period and 4 to 28% per site during the high price period, with an average of 9% and 14% overall for the two price periods.

The 2005 automated CPP test used a new automation server renamed as the DRAS – DR Automation Server. This server was operated at a secure industrial grade hosting facility designed to accommodate scaling up the technology in future years.

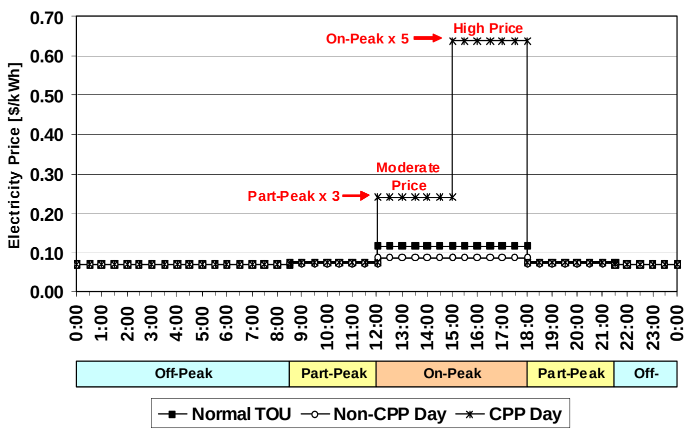


Figure 2. Critical peak price tariff compared with TOU

2.4. 2006: Scaled Up Automated CPP

Following the pilot automated CPP test in 2004 we began a more formal partnership with PG&E's Emerging Technologies Program. In an effort to transfer the expertise of the automation system installation efforts from LBNL to a third party, we developed a qualifications procedure for third-party engineering services. Initially named the DR Integration Services Company, or DRISCO, this service company was renamed in 2007 to an AutoDR Technical Coordinator.

In addition to recruiting new sites into the program, we had about eleven sites that had fully automated CPP response for the entire summer with 12 events. More importantly, we provided this automation system through a severe heat wave in July 2006. Each site continued to reduce their loads over many days during this 1.5-week event. None of the sites opted out or overrode the automation capability, although that option was available. Figure 3 shows an automated demand response shed at an office building in Martinez California. The shed shows a classic response with the first level of response based on resetting the zone temperatures up a few degrees, and second level reset response during the three-hour high price period. Over 100 kW was shed during the high price period with no rebound when the building goes into unoccupied mode after 6 pm.

Among the Auto-CPP sites, site responses to 125 events were fully automated and evaluated in this study. The average peak demand reduction was 14% of the whole-facility load based on the three-hour high-price period.

As we brought the technology out to a large customer base we found that the Internet relay had some communications security issues for some customers. A hole in the corporate firewall was some times needed to allow the relay onto the network. As a result of that finding, a new client was developed. This technology, known as the Client and Logic with Integrated Relay or CLIR was developed as an IT friendly "plug and play" automation client. It is typically installed inside of the secure enterprise network and "polls" for CPP event information using 128 bit secure socket layer (SSL) encryption and authentication using HTTPS protocol. HTTPS is also used for most online financial transactions. No modification to corporate enterprise firewalls is required.

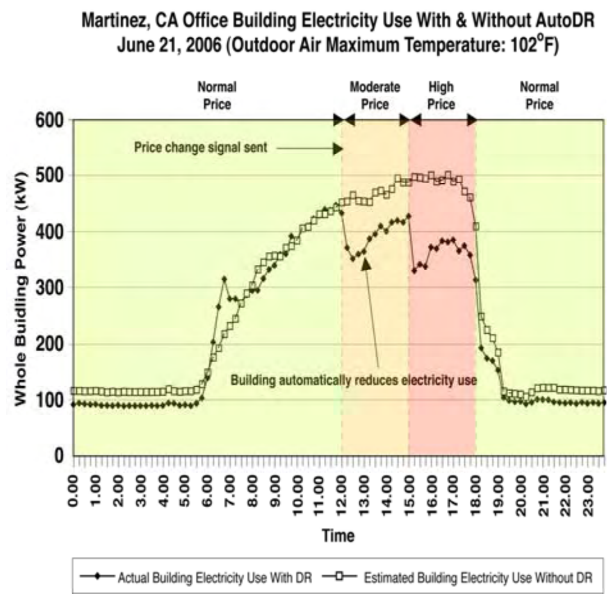


Figure 3. Example of load shape change with AutoDR

2.5. 2007: Commercialization and Program Expansion

Following the hot summer of 2006 the California Public Utilities Commission requested the three California Investor Owned Utilities to partner with the Demand Response Research Center to begin using AutoDR technologies. As part of that effort we developed a more formal definition of AutoDR to outline the principles for the automation system design. **Automated Demand Response for commercial and industrial facilities can be defined** as fully automated DR initiated by a signal from a utility or other appropriate entity and provide full-automated connectivity to customer end-use control strategies.

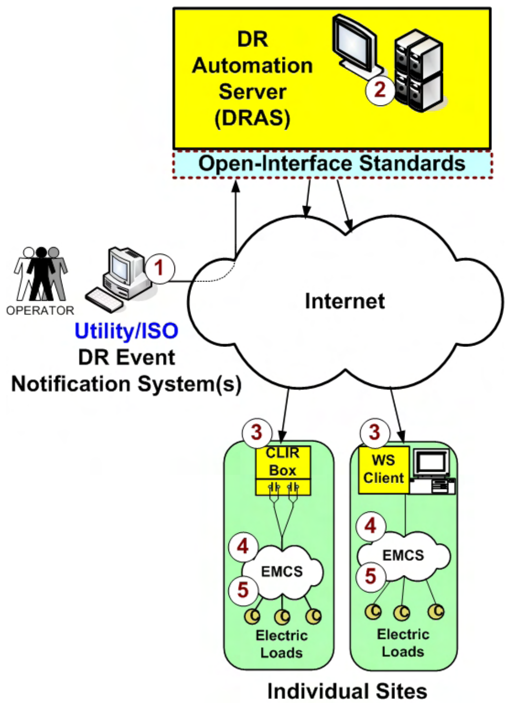
Signaling - AutoDR technology should provide continuous, secure, reliable, two-way communication with end-use customers to allow end-use sites to be identified as listening and acknowledging receipt of DR signals.

Industry Standards - AutoDR consists of open, interoperable industry standard control and communications technologies designed to integrate with both common energy management and control systems and other end-use devices that can receive a dry contact relay or similar signals (such as internet based XML).

Timing of Notification - Day ahead and day of signals are provided by AutoDR technologies to facilitate a diverse set of end-use strategies such as pre-cooling for "day ahead" notification, or near real-time communications to automation "day of" control strategies. Timing of DR automation server (DRAS) communications must consider day-ahead events that include weekends and holidays.

The AutoDR architecture has five steps (Figure 4).

Figure 4. Automated Demand Response Architecture



The steps are as follows:

1. The Utility or ISO defines DR event and price signals that are sent to the DRAS.
2. DR event and price services published on the DRAS.
3. DRAS Clients (CLIR or Web Service Software) request latest event information or price from the DRAS every minute.
4. Customized pre-programmed DR strategies determine action based on price.
5. Facility EMCS carries out shed based on DR signals and strategies.

The San Diego Gas and Electric collaboration is focusing on a demonstration with DR aggregators. The Southern California Edison demonstration is similar to the 2006 PG&E Automated CPP project except that a third-party program manager, Global Energy Partners, is managing it

The PG&E AutoDR program was expanded to include both CPP and demand bidding. Demand bidding allows a larger population of customers to participate because they do not need to go onto the PG&E CPP tariff. The bidding automation uses a standing DR bid that triggers an automated response whenever the program is called. The 2007 PG&E AutoDR program also included recruitment coordinators and technical coordinators to market, evaluate, configure, and manage the automation systems. Over 22 MW have been recruited into the program.

3. RELATED DR BUILDINGS RESEARCH

The DRRC has been actively evaluating the capability of large customers to respond to automated DR signals. While the focus was initially on commercial buildings, we are beginning to examine end-use control strategies that can be automated in industrial facilities as well. Key commercial building research projects have included the following

3.1. Pre-Cooling Field Demonstrations

One of the most important DR strategies for hot summers is to reduce cooling electricity use during DR events. Research. The DRRC has sponsored several years of field trials in both small and large commercial buildings to understand of pre-cooling can be successfully deployed to improve comfort and demand responsiveness [8]. Shifts over 2 W/ft^2 have been conducted, and in some cases energy use can be reduced along with peak demand. The AutoDR day-ahead and event pending signals have been used to automate pre-cooling.

3.2. Demand Responsive Lighting

Lighting systems can be an excellent end-use for DR. The DRRC has funded a scoping study to characterize existing strategies for DR lighting and emerging and advanced technologies. Addressable and dimmable lighting systems with centralized control can offer daily energy efficiency and excellent dispatchable, year-round DR capability. Further research is needed to explore how to design and control such systems. Advances in software are needed to ensure usability and performance [9].

3.3. DR Control Strategy Tools and Guides

Two significant barriers toward scaling up DR participation in commercial buildings are a) the lack of knowledge regarding what strategies are feasible for DR and b) estimating the size of the peak load reduction. To address the first barrier the DRRC created a guide to DR control strategies that is based on engineering principals and lessons from the implementation of AutoDR in over 40 buildings [10]. We have developed two downloadable whole-building simulation tools help estimate the peak demand reduction for different HVAC strategies. One tool is for single zone packages HVAC and the other is for built-up HVAC systems. Further work is needed to make the tool generalizable to a larger set of buildings, climates, and DR strategies.

4. NEXT STEPS AND FUTURE DIRECTIONS

This paper has presented the history and status of automated demand response research and initial commercialization activities in California. The research began with advanced control and energy information systems that could host XML-based signals. Recent work has included automating relay signals with Internet based communications in a secure, open web services architecture. Research on commercial buildings control strategies has also shown good potential for wide spread demand response. Future efforts include standardization of the communications and signaling systems, and efforts to move the technology into future building codes and standards. This technology is also described in a companion paper [11].

5. ACKNOWLEDGEMENTS

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Optimizing Retail Contracts for Electricity Markets

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Abstract

The Olympic Peninsula Testbed Demonstration in Washington State allowed residential electricity customers the choice of three different types of retail electricity rates; a time-of-use price, a fixed price, and a 5-minute real-time price. Each of these rates structures has advantages and disadvantages for both the residential consumers as well as the utility offering them. This paper focuses on a methodology to select the mix of rate types a utility should offer to its residential consumers given the various objectives it seeks to achieve. The method used to determine an optimal mix was borrowed from stock market portfolio theory and results in what is referred to as the Efficient Frontier. This solution defines an optimal mix of contract types among many possible combinations.

Efficient Frontiers in Stock Portfolio Theory

The concept of efficient frontiers was introduced in 1957 by Nobel Prize winner Harry Markowitz as part of the Capital Asset Pricing Model (CAPM) for portfolio theory. The theory is based on the idea that combining several stocks into a portfolio will yield decreases in overall risk below that of any individual stock while retaining high returns.

Figure 1 depicts this idea. The dark shaded region shows all possible ways (weightings) to combine a group of stocks to make up a portfolio. Anywhere on the top leading edge of this region (called the efficient frontier) provides the optimal combinations (weightings) of these stocks for all possible portfolios that can be created. This edge provides the highest return for the lowest risk. Why would a person wish to invest in a portfolio in the central area of this curve? They wouldn't, since combining the same stocks in a different manner can always increase your return without increasing your risk or analogously, decrease your risk for the same return. In the case of stocks risk is defined as the volatility of a stock's price. We will see that the definition of risk differs for electricity rates.

In its truest form, Figure 1 simply shows how normal random variable distributions combine to form a unique random variable distribution. This concept can be used to estimate the best (or optimal) way to combine any set of normal random variables given a clear objective.

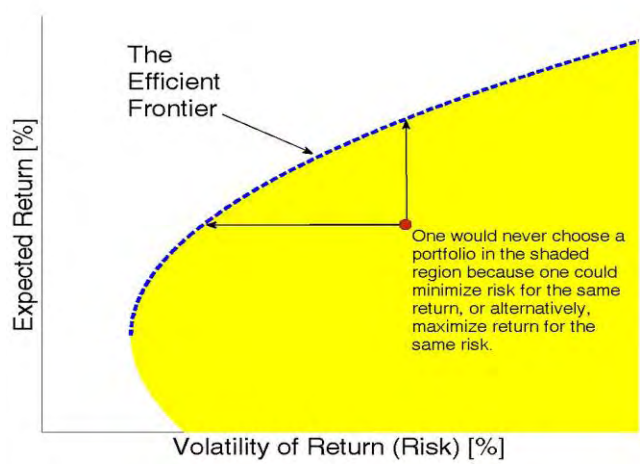

Figure 1. Efficient Frontier for a Stock Portfolio

We will use these principles to look at random variables generated by electricity markets, in the case retail-level markets. We pose the questions, "Given several types of rates that can be offered to customers, what is the optimal combination customer subscriptions to these rates given my objectives"? In the Olympic Peninsula Testbed Demonstration, we tested three retail electricity rates: a fixed price, a time-of-use price, and a 5-minute real-time price. Each of these rates offered electricity to customers who in different ways. Fixed-price customers paid the same price all year. Time-of-use customers paid a daily on-peak or off-peak price, which changed seasonally. Real-time price customers paid a price derived every 5 minutes based on the true cost of delivering the electricity during that period.

Each rate was characterized by data collected over a one year period that make up the random variables needed to perform the efficient frontier calculations. Note that the interpretation of the results for the calculations in utility markets that follow do not necessarily have the same implication as they do in stock portfolio analysis. For example, a point on the efficient frontier in portfolio analysis is by definition considered "good", whereas in evaluating utility market structures, the same part of the curves can only be judged as good or bad in the context of the utility's objectives. This analysis does not yield conclusive directives. Instead it provides a rich mechanism to evaluate the consequences of any given rate offering mix. Whether one rate offering mix is good or bad depends upon the objectives of the utility.

1.1. Random Variables and Normal Distributions

It is essential to understand what random variables are. Figure 2 shows a set of normally distributed random numbers. There is a portion of this data that appears random, such as the scattering effects of the points, and a portion of the data that does not appear to be random at all, such as clustering around the average, and the typical spread of the data around the average. These particular random variables have mean (or average) equal to 2, and their standard deviation (the average distance of each point from their collective average) of 0.2. The manner in which we describe these random variables (by a mean and a standard

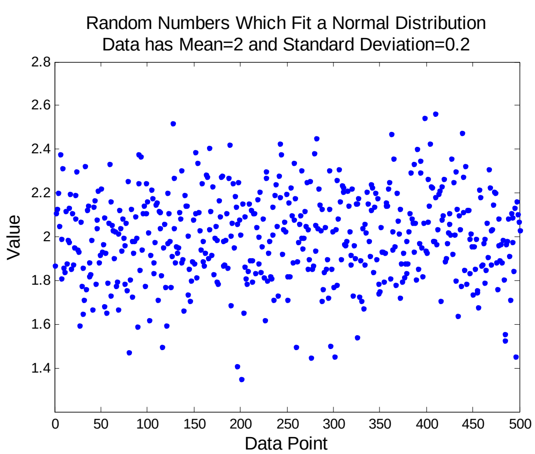

Figure 2 Normally Distributed Random Data

deviation) completely identifies this random variable set. For random variables, we don't care what the actual values are, but rather what the data as a whole looks like. When we consider the data in this manner, we allow for the fact that the next set of data will be completely different, yet will have the same mean and standard deviation. This allows us to evaluate results of events knowing that the particularly values we observe change, but their mean and the standard deviation remain constant.

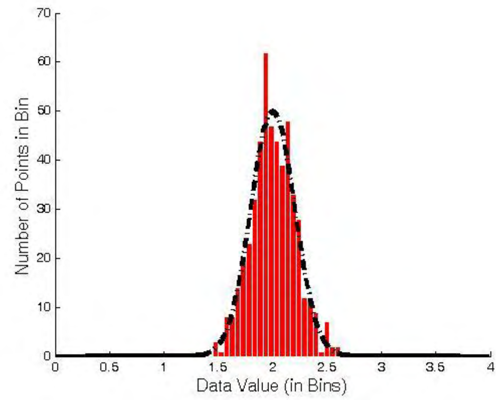

Figure 3 Histogram of Normally Distributed Random Data With Mean=2 and Stdev=0.2

Figure 3 shows a histogram of the same data set seen above. The solid bars constitute a histogram that characterizes the data. This format allows comparison of the data to the curve of a normal or Gaussian distribution. The dashed line is a mathematically defined probability density function based on the mean and standard deviation of the random variables above. If the data fits a normal distribution, then we can claim that the random data is "normal" supporting our conjecture that even though the values may change from one observation to the next, the mean and standard deviation remain constant. From this analysis, we conclude that the data is indeed normal (confirmed by the fact that the data set was created using normally distributed random variables).

The equation below defines a set of random variables by a probability density function. There are only two variables in this equation: the mean, μ; and the standard deviation, σ. These two parameters are sufficient to completely define a normal random variable distribution containing any number of data points.

$$N(\mu,\sigma^2) = \frac{1}{\sqrt{2\pi\sigma^2}} e^{-(x-\mu)^2/2\sigma^2}$$

Normal Probability Density Function

1.2. Portfolios: Combining Normal Distributions

Consider two different normal distribution curves, each completely defined by its respective mean and standard deviation, as shown in Figure 4. These two curves represent data from two independent sources, meaning that no observation in one is in any way related to an observation in the other. The first normal distribution curve might represent income from growing wheat, while the second normal distribution curve might represent income from growing barley. Suppose we want to know what income to expect if we grow both wheat *and* barley. We create a new distribution curve that is a weighted combination of the other two. We do this by combining the expected values, μ, and the variances, σ, of the two given normal distributions as follows:

$$\mu_{new} = \omega_1 \mu_1 + \omega_2 \mu_2$$

$$\sigma_{new}^2 = \omega_1^2 \sigma_1^2 + \omega_2^2 \sigma_2^2 + 2\omega_1 \omega_2 \rho_{12} \sigma_1 \sigma_2$$

Where ρ is the covariance between the two data sets and ω is a weighting factor to determine how much of a given distribution is to be added (note that $\omega_1 + \omega_2 = 1$)

The lightly marked normal distribution functions are obtained for various proportions of wheat and barley. There are many of these curves, each representing the sale of a different mix of wheat and barley. But together, all these curves represent all possible income levels by growing different combinations of wheat and barley.

One might assume that the mean value of each curve would simply follow a relatively straight line between the two curves, but this is not at all what happens. This result confirms that something very important is going on.

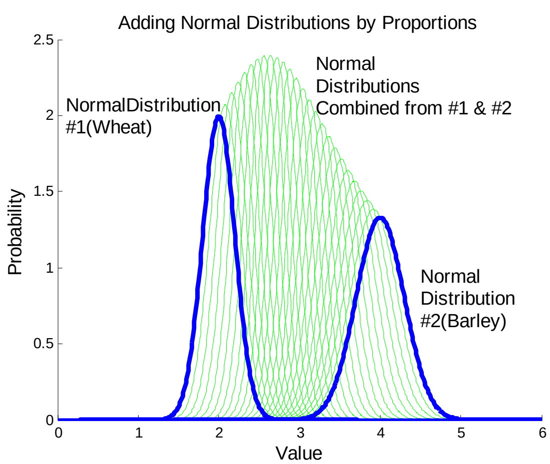

Figure 4 Combinations of Two Normal Random Variable Distributions

Looking at this a different way, we recall that each normal distribution data set can be defined by just two numbers–a mean and a standard deviation. Using these only, we develop what is called the efficient frontier, as shown in Figure 5. Mathematically, this process is simply combining the probability density functions together by the proportions listed.

In the wheat/barley example, we consider what mixture of wheat and barley to grow knowing the expected income (mean) and variability in income (standard deviation) of all possible combinations of wheat and barley. Clearly over a period of many years, the mean income is maximized when only barley is grown. But what about the variability of income? In this context, the standard deviation refers to how far from the mean income each year's income is. If the uncertainty of income is not important, then it is clear that barley is the preferred growing strategy.

However, if the variability of income is a consideration, such as when a steady income is desired, then some income must be sacrificed in exchange. This is not much different than paying interest on a short term loan to cover seasonal operating expenses. The variability in income is minimized at the optimal mix of wheat and barley with a mean of 2.6 and a standard deviation near 0.165. The portion of the graph made as small circles constitutes the efficient frontier. Where along that continuum you decide to operate is a matter of preference. You would never want to drop below this optimal point, however, as you would be increasing your variability of income while decreasing your income. What if you sold wheat exclusively? Given what we see above, by selling a little barley along with your wheat, you would increase your income and make it more stable too.

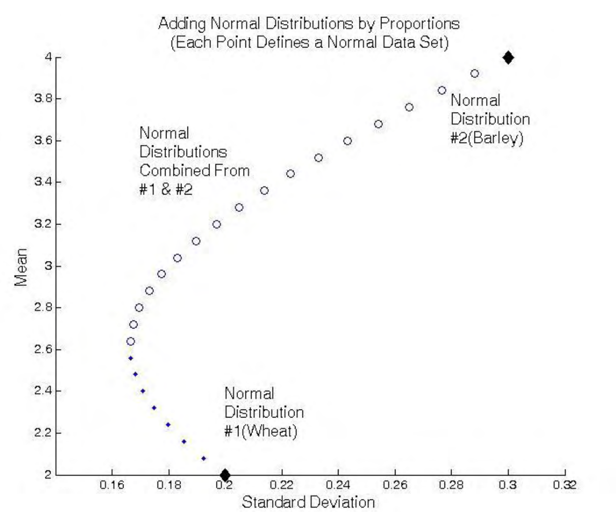

Figure 5 The Efficient Frontier

1.3. Retail Electricity Markets

Now we can consider the electric power utility industry. In the Olympic Peninsula Testbed Demonstration, there were three types of residential rate contracts offered to consumers of electric power: fixed price, which charged a fixed rated for electricity usage in dollars per amount of energy used, time-of-use price, which charged two different seasonal rates for electricity that were consistently applied for specific hours of each day, and the real-time price, which charged higher rates for electricity usage when the power system capacity was at or near its capacity limit and lower prices when the system had excess capacity.

1.3.1. Optimizing Contract Selection for Peak Power

Figure 6 shows the peak energy usage. Only data from the times of the year and day when energy consumption was high were used for this analysis– specifically the time of year from November 1st to December 8th and the hours of the day from 6am to 9am and from 6pm to 9pm. This data represents the times when the electric power system was at its highest load relative to the available capacity, and therefore represents the best time to evaluate at how the different contract types influenced (both suppliers and consumers) the systems response to capacity constraints.

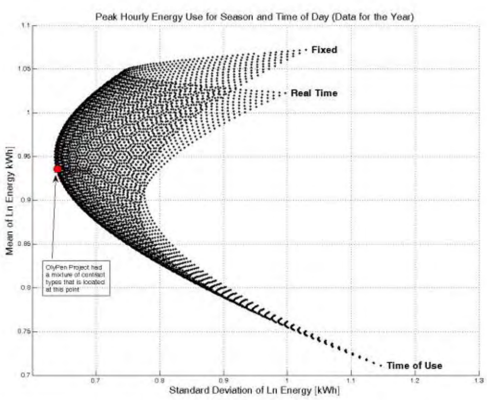

Figure 6 Contract Type Impacts on Peak Power

Figure 6 shows the efficient frontier analysis based on this peak condition data. The shaded area represents all possible proportions of combining the three markets types- and the sharp points at the ends of the shaded regions represent a market that is not mixed at all, but consists only of that type of contract. For example, the word "Fixed" appears next to a corner point near (1.05kWh, 1.07kWh). That point represents a mixture of contract types where Fixed type = 100%, Time of Use type = 0% and Real Time type = 0%. Moving away from the extreme points in the shaded region, other contact types start getting mixed together. The details of how to determine what the mix is will be explained below. The Olympic Peninsula project had a mixture of roughly 1/3 of each contract type.

To interpret Figure 6, the utility's objective must be known. Presumable, the utility would like to reduce peak energy during its times of high load or limited capacity. Doing so allows the utility to defer very expensive system capacity upgrades to accommodate the increase in electricity use during these periods. This objective tells us that the peak energy use (y-axis) should be as low as possible.

So what about the variability (x-axis) of the peak energy use? At first thought we might say that we want the variability to be low. However, if we take it as given that the peak energy is low, we would want the participants to be responsive- that is- to change their energy use as a result of price changes. This implies that we actually desire a high variability. Together, the evaluation above points to the desired market structure as the Time of Use rate by itself- not mixed in combination with any of the two other rates structures. But this evaluation is incomplete, and does not consider other objectives of the utility, such as Gross Margin. Let's consider these affects next.

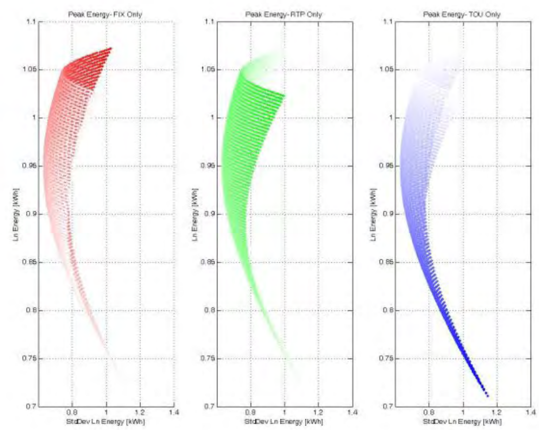

Figure 7 Contract Type Impacts on Peak Power (Contract Types Separated)

Figure 7 is simply Figure 6 'taken apart', allowing one to see what the constituent contract mixes are that make up the entire curve. For example, the Olympic peninsula project is shown in Figure 6 at the point Stdev=0.64 and Peak Energy=0.93. Looking at all three graphs in Figure 7, one can see that this point has shading in all three curves. This implies that all three curves participate in the contract mix at that point. Analogously, one can use Figure 7 to help determine the contract options for a desired Stdev and Peak Energy. Figures 6 and 7 are better represented by using a single colored version of Figure 6, allowing the color to represent the contract type- as is represented below in Figure 10 for the Gross Margin analysis. The x-axis on these three graphs has been squeezed in order to allow sufficient space in the document, however, the range of the axes in Figure 7 are the same as those in Figure 6.

1.3.2. Optimizing Contract Selection for Gross Margin

Gross Margin is defined as the revenue generated by the sale of electricity minus the cost of that electricity. It does not include costs of infrastructure, labor, taxes, overheads, or other fixed costs. It simply gives an early preview of what profits might look like. Omitting these other charges helps keep this financial metric relevant to a broader range of companies- all of which can add back in their own specific fixed charges. Unlike the previous analysis which looked only at peak periods of electricity use, this analysis uses data for the residential homes for the entire year at 24 hours per day and 7 days per week. Note that this is the exact same customer set, but we are now considering data from a different period.

One might expect the same curve as before, but that is not the case. Earlier we considered peak power usage, and now we are looking at gross margin–both important to a utility, but each the basis for completely different objectives.

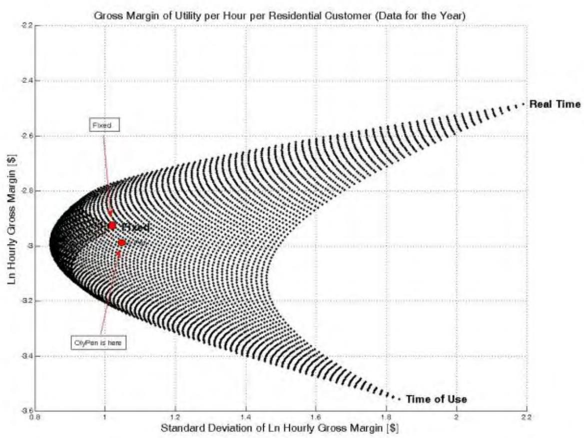

Figure 8 Contract Type Impacts on Gross Margin

Regarding the utility's objectives, we assume that they would like a high gross margin. Regarding the variability of this gross margin, we might consider that all else being equal, the utility would like it minimized. However it is probably not very important in this analysis since seasonal affects will likely have more impact on gross margin variability than would contract type. Because low variability implies a lower gross margin, each utility must establish for itself where on this upper leading edge it would prefer to operate.

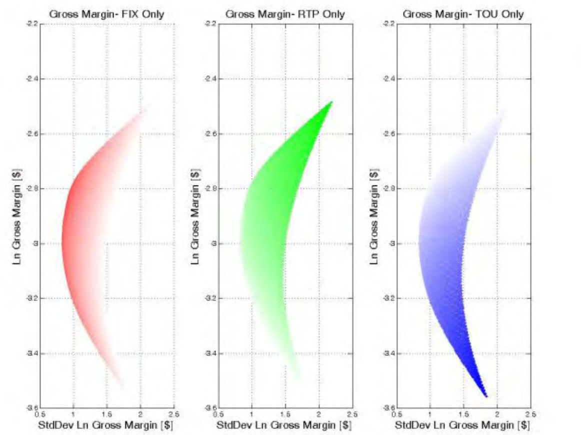

Figure 9 Contract Type Impacts on Gross Margin (Contract Types Separated)

As was the case with Figure 7, Figure 9 'takes apart' the contract types embedded in Figure 8, allowing one to observe which contract types contribute to a given contract mix. Again, the x-axis on these curves have been squeezed to allow sufficient space to insert them into this document.

1.3.3. Comparing Gross Margin analysis to Peak Power Analysis

By now, it seems obvious that picking a contract mix which minimizes peak power does not necessarily result in an optimal contract mix that maximizes gross margin. Earlier, we concluded that the data supported time-of-use contracts as best for reducing peak power and thus deferring capacity upgrades. Follow up analysis shows that gross margin is maximized by emphasizing real-time contacts whereas the time-of-use contract type minimizes gross margin.

It should now be apparent that this problem requires optimization, but not all the information needed is available. It would be very helpful to know how a point on one graph is translated to the other graph. The graphs so far have not shown this information,

Figure 10 shows a 3-D surface situated above the region taken from Figure 8. The 3-D surface reveals information about the mix of contracts for all points on the efficient frontier plot. The mixture has been represented by color where all red indicates fixed-price contracts, all blue indicates time-of-use contracts, and all green indicates real-time contracts. Mixtures of contracts are represented by mixing the colors in similar proportions. Therefore, areas on the map with a some red, a some blue, and a some green indicated a contract mix in that proportion. As we can see, the Olympic Peninsula Testbed Demonstation point is one such representation, with about 1/3 each. The numeric value along the z-axis represents the combined colors and can be ignored–it is simply a convenient mathematical method of separating multiple solutions along this axis.

Folding over of the 3-D surface implies that multiple solutions can be found for some regions. One can clearly see the fixed-price contract type is folded up and back over the minimum volatility region. This superimposed area implies that more than one contract mix exists for a number of points near the efficient frontier. This means that is more than one choice of contract mix to achieve a given objective on the efficient frontier curve (in the areas where these solutions overlap each other).

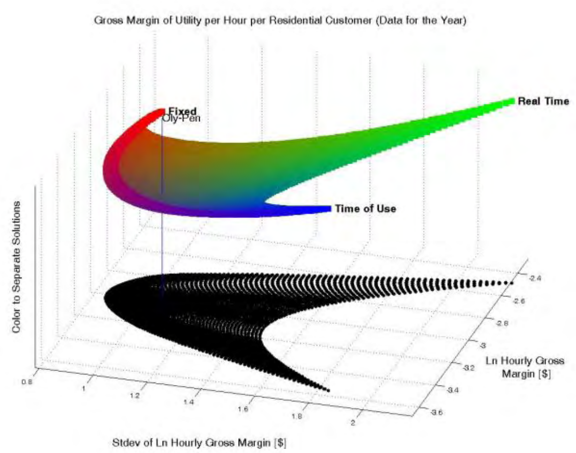

Figure 10 Contract Type Impacts on Gross Margin Shown in 3D With Color Denoting Contract Type

Qualitative Optimization

We observed above that time-of-use contracts were more effective for reducing peak power and the real-time contracts for maximizing gross margin. We now have a method to determine what mix of contracts best suits any the objectives of the utility- and are able to understand the resulting tradeoffs in peak shaving and gross margin for any given portfolio of contracts. Of course, there are more than two criteria that may be considered in selecting a contract mix. The technique below shows how to create other efficient frontiers, and it is up to the reader to evaluate these based on specific objectives.

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Biographies

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Appliance Interface for Grid Responses

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Abstract

A successful, rapid integration of technologies from three different companies was achieved as part of the Grid Friendly™ Appliance Project. Therein, a simple but effective interface was defined between a vendor's commercial energy management system control module, an experimental electronic sensor and controller, and a smart appliance. The interface permitted each entity to use its preferred, proprietary communications up to the interface without divulging any protected or sensitive attributes of the entity's hardware, software, or communication protocols.

Those who participated in this integration effort recognize the potential value of the interface as an interoperability model, which could be expanded and extended with participation and buy-in from a larger community of stakeholders. The result could become a universal interface for the communication of demand response objectives to appliances and other small loads. We focus here on the business and marketing challenges.

1. SIMPLE, APPLIANCE CONTROL INTERFACE DEMONSTRATED

The authors began their collaboration during the Grid Friendly Appliance Project [1]. This project modified residential hot water heaters and clothes dryers to be responsive to the Grid Friendly appliance controller. Pacific Northwest National Laboratory (PNNL) designed the controller to reside in an appliance and monitor system frequency. During an underfrequency event the controller signaled the appliance to shed load. A fourth collaborator, Invensys Controls, won a competitive project solicitation to supply persistent monitoring of the controllers and appliances via components of their GoodWatts™ energy management system.

Practical limitations due to manufacturing constraints and safety issues forced the project to adopt a limited integration with the controller external to the appliance. However this change created the seed for the new approaches discussed in this paper.

With the controller external to the appliance, the next critical step was to meld the communications between the dryer, controller, and monitoring system. Understandably, both Whirlpool and Invensys use proprietary serial communications on their respective products. To also ease the testing and debugging phase, a decision was made to reduce communication at the interface down to only three Boolean signals that could be communicated on dedicated wires indicating the following messages:

GFA - An underfrequency event has been recognized by the Grid Friendly controller. Appliances should immediately reduce their power consumption.

En - This signal asks the appliances to respond to a traditional direct load control program. The water heater turns off. The dryer beeps, displays "En", and requires the consumer to acknowledge if they want to override this request and initiate a drying cycle.

Pr – This signal indicates that a high price condition is in effect. The appliance should advise its owner to defer energy consumption, or to respond in a way appropriate for the particular appliance receiving the signal. The project dryer will beep and display "Pr" on its panel.

While remarkably simplistic, these basic signals captured these authors' imaginations and demonstrated how a simple appliance interface can fulfill the basic needs for Demand Response (DR).

1.1. New Approach for Responsive Appliance Loads

Evaluation of the project with an eye towards commercialization led to the following potentially economical demand response opportunity. The basic solution would be a standard that defines a single physical socket to be located on all major appliances. The pins of the socket provide power to a communication device that the appliance owner would "plug in" at a later date. The pins relay basic Boolean logic signals between the appliance and device, which may then communicate externally via any chosen medium and protocol. Optionally, a serial protocol can be used to communicate not only basic command signals but also more advanced, richer information. The appliance interprets one or more of the defined command signals and then responds as designed by the manufacturer, and as has been configured by the customer at the appliance's user interface.

2. PROJECT BACKGROUND, GOALS, AND LIMITATIONS TO BE OVERCOME

What factors are motivating the furtherance of the concepts studied and demonstrated?

2.1. Smart Grid Developments

The Grid Friendly Appliance Project that initiated the authors' collaboration is a small part of a larger movement to modernize and create a smart electric power grid. One emphasis of this movement should be to overcome financial and technical barriers that have thus far limited the participation of responsive loads. Loads can accept responsibility for peak energy management, system stability, regulation, spinning reserve, and other ancillary services far beyond what is now practiced. Appliances and other small loads especially remain a largely untapped load resource.

2.2. Advantages and Opportunities

Where will the entities who adopt this approach find benefits and opportunities?

2.2.1. Interoperability between Complex and Proprietary Systems

The ideal appliance interface will be interoperable, meaning it will possess a defined, standard physical interconnection and will use a known, common language. There appears to be agreement up to this point. But most competing "interoperability" standards and protocols rely on increasingly complex serial communications and class structures residing on evolving media. Regrettably, numerous workable standards and protocols lie unused. Few standards and protocols are practiced by competitors without the evolution of proprietary, non-interoperable versions.

The definition of a simple pin interface for the communication of energy needs, where the assertion of pins from the utility side is interpreted as a request for an appropriate appliance response, could break this cycle and could result in an enduring, functional, and truly interoperable interface. The adoption of this simple pin interface would not preclude also exchanging rich serial communications with those few appliances that will require it, although most will not.

2.2.2. Does not Attempt to Pick a Winning In-home Communication Method

The proposed interface permits fair competition. It does not preclude the advancement of propriety and non-proprietary means of communication and special product features that may be enabled by such advancements. For example, makers of building energy management systems could expand their product offerings by providing the utility-side communications to the appliance interfaces.

2.2.3. Less Susceptible to Obsolescence

Product obsolescence is a valid concern. Utilities have become accustomed to equipment amortization over 20 – 30 years, and appliances can also last decades. New appliance models may take several years to develop. There is a fundamental mismatch between the slow turnover of appliance products and the rapid obsolescence of digital products like those that might emerge to talk to these appliances. Annual appliance sales equal roughly 10% of the current installed base. If industry were to begin offering a viable interface today, it could take a decade to saturate the appliance load capacity, but that capacity may endure several more decades thereafter. In contrast, will your present laptop computer remain useful after 10 years?

2.2.4. Create a Global Solution

Until now, demand response programs have been offered regionally. This is a mismatch with appliance manufactures, which focus on a more global design. Even a region as large as a state is determined to be too small to warrant unique appliance model designs and the logistic management to direct these models to the appropriate region. This global approach may present a real opportunity and advantage for the practice of economical demand response for appliances and small loads.

2.2.5. Eliminate the Need for Professional Installation

The cost to install a single end-use point has been as high as $350, including professional licensed installation, permitting, and the necessary equipment. Few appliance types can justify this cost. Rather than having an installer drill holes, string wire, and install ugly boxes to gain a seasonal compensation of $10 per month, the customer should receive a small module to plug into a standard socket on their appliance. Its installation may be electronically verified by the utility.

3. THE BUSINESS CASE FOR UTILITIES

A number of factors are pressing utilities to

- seek green capacity and energy solutions
- improve the value proposition to end-use customers
- show responsiveness to Energy Policy Act of 2005
- find a cost effective version of the "smart grid."

3.1. Advanced Metering

Advanced Metering Infrastructure (AMI) is desirable, but it is not a necessary component for the implementation of demand response. Many utilities (such as PGE) expect to utilize AMI networks to send demand response price and control signals. However, cheaper communication paths might be feasible if demand response is the only or main benefit of the technology. Various home networks, Power Line Carrier (PLC), or wireless solutions are possible. But having a communications technology-neutral appliance end point enables a variety of utility-specific business cases to co-exist while utilizing the same DR-enabled appliances.

3.2. Verification of Demand Response Participation

The serial interface of an appliance interface standard should support acknowledgement of a demand response command, but verification needs in the utility industry are not yet well defined. Some demand response systems operate today without direct verification. Acknowledgement is useful, but may not be considered a requirement.

3.3. Available Load Resource from New Appliances

A Federal Energy Regulatory Commission (FERC) report indicates that the existing direct load control in the residential sector is 7,000 MW [3]. Direct load control has been available since the mid 1980s, but after 20 years we have less than 1% of the peak system load under control. As shown in Table 1, 32 million new appliances sold each year contribute 16 GW of new controllable capacity. Optimistically, in one year one could capture more than twice as much direct load control as exists today. To achieve results near this optimistic projection, a large fraction of new appliances must come to participate by market forces or by mandate. Furthermore, the projection has assumed that all of the participating appliances' load would be curtailed and never overridden, which may not be practicable for all shown appliance types. The appliance load resource could be earned over several years while utilities and appliance manufacturers learn and then design and use these new appliance resources.

3.4. Old Economics

In previous cases direct load control was not economic compared to building a generation plant to serve system peak load. A simple cycle combustion turbine installed for this purpose has a first cost of about $400/KW. After one amortizes the cost and pay for fixed labor and maintenance, the annual cost for this plant is about $70/KW. Using the total cost of $350 per control point (Section 2.2.5) and data from Table 1, one can see that the only appliance load resource that presently competes with generation on a cost per kW basis is central air conditioning.

3.4.1. New Economics

Adding a socket on every appliance is not as simple as it sounds. The good news is that marginal cost per appliance is probably $2 to $5. But the one-time recurring engineering cost for mechanical, electrical, control, tooling, and safety considerations is probably $100K to $500K for each

Table 1 New Appliances Placed Annually in Occupied US Households

Appliance	Replacement in Existing Homes: % Electric	Avg Life	Units Sold in millions	Penetration in New Homes: % Electric	Units Sold in millions	Coincident Peak kW contribution per Appliance btwn 4p & 8p (summer): Avg Day	Pk Day	New Appliance Load Contribution in GW: Avg Day	Pk Day
Water Heater	38%	15	2.8	40%	0.4	0.60	0.60	1.9	1.9
Window AC	22%	13	1.8	25%	0.2	0.50	0.90	1.0	1.9
Central AC	54%	25	2.4	60%	0.5	1.00	3.00	2.9	8.7
Stove	59%	16	4.0	60%	0.5	0.48	0.46	2.2	2.1
Refrigerator	110%	18	6.7	100%	0.9	0.10	0.11	0.8	0.8
Dryer	57%	15	4.2	60%	0.5	0.15	0.14	0.7	0.7
Freezer	32%	20	1.7	30%	0.3	0.10	0.10	0.2	0.2
Dishwasher	53%	13	4.5	60%	0.5	0.05	0.04	0.2	0.2
			28.0		**3.9**			**9.9**	**16.4**
Assumptions					Average Benefit per Appliance=>			0.3 KW	0.5 KW

Market Saturation from Table 963 Statistical Abstracts 2006			
Number of US Households 2007	109.3	million	For reference in 2007
Number of New Households	0.9	per yr.	US Peak Summer Load Forecast is 790 GW

appliance line. Collectively across multiple OEMs, the one time cost is probably $100 to $200 million investment. However, amortizing this cost across 32 million appliances per year over 5 years adds only another $1 per appliance.

For a medium sized utility like PGE (700,000 residential customers) this means about 200,000 new appliances are added each year. After 5 years, a program might control 1 million appliances with a potential benefit of about 500 MW. This is a serious resource, and PGE could afford to spend $200 million to capture it. If it reserves $20 million of this for one-time development and program startup costs, PGE could afford to spend $180 per home.

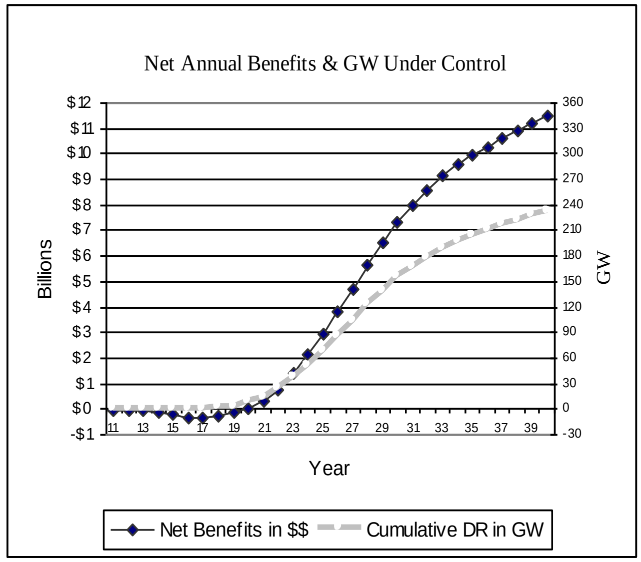
Under the new proposed approach, PGE would more likely spend about a fifth of this. The initial cost for the communications interface might be $50, but with up to 32 million additional appliances appearing each year, and as the product matures, there is no reason not to expect that the product couldn't eventually be stocked at supermarkets for perhaps $10 each.

After an initial education campaign, marketing costs should be small. Since the cost of trying the program would be so low and the communication device might be installed and uninstalled by the appliance owner, there would be no risk to the consumer, and recruitment will occur by word of mouth experience from their friends. There would be no new control system to master; there would be only the appliance controls that the customer has already mastered. If a customer were to sign up for a utility program and didn't like the consequent lifestyle or comfort impact, then undoing their enrollment would be totally transparent and 100% under their control. This solves the problematic poor customer experience that has hampered some previous demand response programs..

3.5. Societal Benefit/Cost Analysis

In the early years, since the marginal societal cost per appliance is likely to be about $50, there is justification to target only the appliances in Table 1 with the largest kW impact. After experience is gained and the marginal cost drops, even control of appliances like refrigerators, freezers, and dishwashers can be captured cost effectively compared to generation.

To account for all of the incurred costs, one must assume a timeline for development and for utility and customer adoption. Figure 2 shows the cumulative GW of demand response from the electric appliances added each year in accordance with the adoption rates in Figure 1. For simplicity, an average capacity benefit of 0.5 kW per appliance (Table 1) is assumed in Figure 2. To compute the annual net benefit from the new appliance capacity, $50 per KW is assumed for the cost of avoided generation. This is a conservative estimate compared to the current cost for peaking capacity (Section 3.4). The conservative benefits were chosen because control of demand resources tends to eliminate some use and shift the rest to a time when the fuel cost per kWh is less. None of the energy cost savings is included in this analysis. Assuming a real, societal discount factor of 3.5%, the net present value of the nation-wide effort in today's dollars is $60 billion.



3.6. Additional Benefits

With 100's of millions of appliances to target, the original concept of autonomous Grid Friendly controller and similar grid-responsive tools could be implemented through the same interface. A discussion of direct demand response addresses but one of several value propositions. There are billions more to be saved in improved transmission utilization and avoided outages. The interface could also further enable other innovations such as a central home controller, demand-side regulation services, automated energy price responses, whole-house battery back up systems, and off-grid products to cost-effectively manage outages.

4. BUSINESS CASE FOR MANUFACTURERS OF RESIDENTIAL DEVICES

Prior to the GridWise Testbed Project [1], Whirlpool Corporation conducted an independent study on special appliance designs to help the consumer interact with time-based pricing such as time-of-use (TOU) and real-time pricing (RTP). The Whirlpool Woodridge Project and Energy Monitoring Pilot [2] when combined with the GridWise demonstration indicate several items of note:

- Consumers must alter their lifestyle to some degree to react to time-based energy pricing structures.
- Consumers are willing to change their use times for certain process-oriented appliance products.

• Appliance design can enhance consumer acceptance of time-based pricing and underfrequency grid response.

4.1. Customer and Appliance Interaction

To design proper modifications, manufacturers need to understand how, when and why appliances consume energy and match this data up with the most likely times of grid stresses. Each consumer may have unique interactions with the appliance and the consumer products involved in the process. We need to understand how much of the appliance power can realistically be affected, during what phase of the process, and at what development and manufacturing cost.

Manufacturers need to understand the consequent impact each energy response might have on users of the appliance. For example, the Grid Friendly Appliance Project [1] demonstrated that turning off the dryer's heating element during a grid underfrequency excursion while leaving the dryer drum tumbling was unnoticed by 97% of the consumers. These are important research findings that shape the design process.

4.2. Business Issues for Device Manufacturers

Consumers make the decision on what, when, where, and whether to purchase appliances. A mass production product in the free unregulated market necessitates further study of the marketability and profitability of a new feature. Questions may include "What will induce a consumer to want a product with this feature?", or "Will there be government and utility incentives to encourage market transformation?"

Due to previously mentioned customization and logistical issues, the logic of our discussion will focus on an economic model that cost effectively enables grid-ready features in mass without customization and without adding logistical expenses.

For illustration purposes, assume a manufacturer makes 5 million dryers a year. Now assume the addition of a grid-responsive interface adds $2 to the cost of the product. This added cost will be taking $10-million of profit directly off of the bottom line. There may not be any guarantee that the $10 million will be recovered because the consumer is not necessarily forced to fund it by purchase of this product.

The manufacturer's challenge is to provide such features that will save them far more than the product cost increment, or to keep the cost down or below standard pricing via incentives to the manufacturer. Various potential cost recovery models have been discussed. See the Pacific Northwest GridWise Testbed Demonstration Project reports [1] for further discussion.

From the business perspective, the cost of development, higher product cost, and communication technologies need to be justified. The amount of energy that can be managed by making appliances responsive to a grid management system appears to be reasonable under the proposed approach.

4.3. Engaging the Residential Consumer via Product Design

There are several basic realizations that have been uncovered in various residential demand response pilots and focus groups. The first is that demand response will affect consumer lifestyles, perhaps some more than others. This could be related to comfort levels or the time of day certain household devices are operated. A second item is that if consumers don't understand and accept the demand response program, they can and will thwart the program, reducing its intended impact. Consumers have voiced concern that they don't want to have to think about energy. They desire a way to automate whatever it is they have to do.

The *persistent* residential devices that operate with virtually no interactions with the consumer (e.g. water heater, HVAC, spa/pool pumps) can be automated to a large degree. *Process oriented* devices (e.g. dishwasher, stove, oven, and laundry) interact with the consumer every time they are used, requiring a different type of automation which must involve the process logic within the appliance's electronic control module.

As new appliance features are added, new sensors and interfaces are introduced, and manufactures of these products continue perfecting their consumer interfaces. Any new grid interfaces need to be melded into the product via these familiar tried-and-true methods. New appliances have "smart" controls that are able to handle some new functions with microprocessor logic. This logic knows the status of the process involving consumables (such as detergent), times, temperatures, and the effect of any changes to the state of the operation. The appliance control already has mechanisms to activate or deactivate the energy consuming components. Therefore expensive external switches should not be necessary.

5. PRINCIPLES FOR THE NEW APPLIANCE INTERFACE

The critical steps in the definition of the simple appliance interface are to

- Define the grid problems that can occur and communicate these conditions and needs to appliance design engineers.
- Define a simple standard protocol used to communicate these unusual events to the appliance using a small number of Boolean signals.

Through these steps, the process leverages the expertise of appliance design engineers to manage appliance grid responses in ways that could not otherwise be addressed. Through the resulting hardware integration, the cost of external control mechanisms (*e.g.* 240-V water heater disconnect) might be reduced. When a grid signal is issued, the appliance manufacturers have designed the device to respond in the best way it can with minimal overhead, cost, and consumer lifestyle disruption.

The remainder of this section lists some of the guiding principals that should guide development of the simple appliance interface.

5.1. Define a Standard that Could be Implemented on Every Major Appliance.

The standard must be independent of any specific communication protocol. Whether a particular region or utility utilizes PLC, Broadband, Zigbee™, HomeNet™, a pager network or any other approach, the message definitions should remain the same. These protocols, if used, should be easily interpreted near or at the appliance.

5.2. Open and Published Protocol

The protocol must be able to be implemented by any device manufacturer on any model of product. Implementation of the interface must be reasonably accomplished using published information only.

5.3. Responses are Described by Objective

Requested responses should be described by objective, not by specific action. For example, an interface request could be defined by the need to shed load immediately. A signal should not specify the turning off of a dryer's heating element. Implicit in this principle is that appliance makers design the responses and should be encouraged to differentiate their products by the superior ways they respond.

5.4. Provide Incentives for Rapid Adoption

Incentives need to be in place that account for the perspective of consumers, manufacturers, utilities, grid operations, government, regulatory, and technology providers.

5.5. Grid-Ready Appliances When Purchased

These appliances are ready to respond to a variety of utility or state energy programs at the time they are purchased and installed. Additional external components, if needed, are installed safely by the consumer.

5.6. Existing Vendors Welcomed

The vendors of advanced metering, communicating thermostats, and premise energy management systems are encouraged to use the interface. These vendors may be instrumental to the interface development as they provide the external communication components. These vendors profit by helping control still more responsive load.

6. THE NEXT THREE STEPS

Three years ago, the authors asked themselves, "What steps can be taken today to have a great demand-side appliance resource installed and ready to participate in various electrical energy programs within several years?" The simplified, low-bandwidth interface described in this paper may be the answer. The approach can be advanced, proven, and implemented by these next steps:

- Define the simple low-bandwidth communication protocol according to the outlined principles.
- Demonstrate the approach alone and in conjunction with a variety of communication infrastructure such as AMI.
- Further engage both appliance manufactures and utilities to help prove their business cases.

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Biographies

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Architecture Concepts and Technical Issues for an Open, Interoperable Automated Demand Response Infrastructure

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Abstract

This paper presents the technical and architectural issues associated with automating Demand Response (DR) programs. The paper focuses on a description of the Demand Response Automation Server (DRAS), which is the main component used to automate the interactions between the Utilities and their customers for DR programs. Use cases are presented that show the role of the DRAS in automating various aspects of DR programs. This paper also describes the various technical aspects of the DRAS including its interfaces and major modes of operation. This includes how the DRAS supports automating such Utility/Customer interactions as automated DR bidding, automated DR event handling, and finally real-time pricing.

1. INTRODUCTION

Since 2002 the process of automating DR programs has been under investigation by the Demand Response Research Center (DRRC) of Lawrence Berkeley National Laboratories (LBNL) and various Utilities in California. These efforts are described in more detail in [1]. This paper describes the technical aspects of the results of those efforts.

As described in [1] **Fully-Automated Demand Response** does not involve human intervention, but is initiated at a home, building, or facility through receipt of an external communications signal. The receipt of the external signal initiates pre-programmed demand response strategies [2]. The authors refer to this as Auto-DR. One important concept in Auto-DR is that a homeowner or facility manager should be able to "opt out" or "override" a DR event if the event comes at time when the reduction in end-use services is not acceptable.

From the customer side, modifications to the site's electric load shape can be achieved by modifying end-use loads. Examples of demand response strategies include reducing electric loads by dimming or turning off non-critical lights, changing comfort thermostat set points, or turning off non-critical equipment. These demand response activities are triggered by specific actions set by the electricity service provider, such as dynamic pricing or demand bidding. Many electricity customers have suggested that automation will help them institutionalize their demand response. The alternative is manual demand response -- where building staff receives a signal and manually reduces demand. LBNL research has found that many building energy management and controls systems (EMCS) and related lighting and other controls can be pre-programmed to initiate and manage electric demand response.

Following the hot summer of 2006 the California Public Utilities Commission requested the three California Investor Owned Utilities to partner with the DRRC to begin using Auto-DR technologies. As part of that effort a more formal definition of Auto-DR was developed to outline the principles for the automation system design. **Automated Demand Response for commercial and industrial facilities can be defined** as fully automated DR initiated by a signal from a utility or other appropriate entity and provide full-automated connectivity to customer end-use control strategies.

Signaling - The Auto-DR technology should provide continuous, secure, reliable, two-way communication with end-use customers to allow end-use sites to be identified as listening and acknowledging receipt of DR signals.

Industry Standards - Automated DR consists of open, interoperable industry standard control and communications technologies designed to integrate with both common energy management and control systems and other end-use devices that can receive a dry contact relay or similar signals (such as internet based XML).

Timing of Notification - Day ahead and day of signals are provided by Auto-DR technologies to facilitate a diverse set of end-use strategies such as pre-cooling for "day ahead" notification, or near real-time communications to automation "day of" control strategies. Timing of DR automation server communications must consider day ahead events that include weekends and holidays.

A key infrastructure component used to automate DR programs is the so-called Demand Response Automation Server (DRAS). Figure 1 depicts a conceptual overview of Auto-DR and the role that the DRAS plays in the over all infrastructure.

As shown in Figure 1 the DRAS plays a crucial role in automating the interactions between the Utility/ISO and the DR program Participants. The DRAS is designed to generate, manage, and track DR signals between Utilities/ISO's to aggregators and end-use customers and their control systems that perform various shed strategies in response to the DR signals.

Each facility or end-use customer hosts a DRAS Client that is responsible for bridging communications between the DRAS and the automated system (e.g. Energy Management Control Systems) responsible for controlling electricity consumption. It may be a software-based client implemented with an existing sub-system or a dedicated piece of hardware whose responsibility is to proxy communications between the DRAS and the EMCS. The latter is depicted by the CLIR box (Client Logic and Integrated Relay) in Figure 1.

2. USE CASES

The DRAS is designed to support two major classes of Utility/ISO and Participant interactions: DR event notification and automated bid submission. How the DRAS is used in each of these functions is detailed in this section.

2.1. Automated DR Event Notification

Almost all DR programs require Participants to respond to

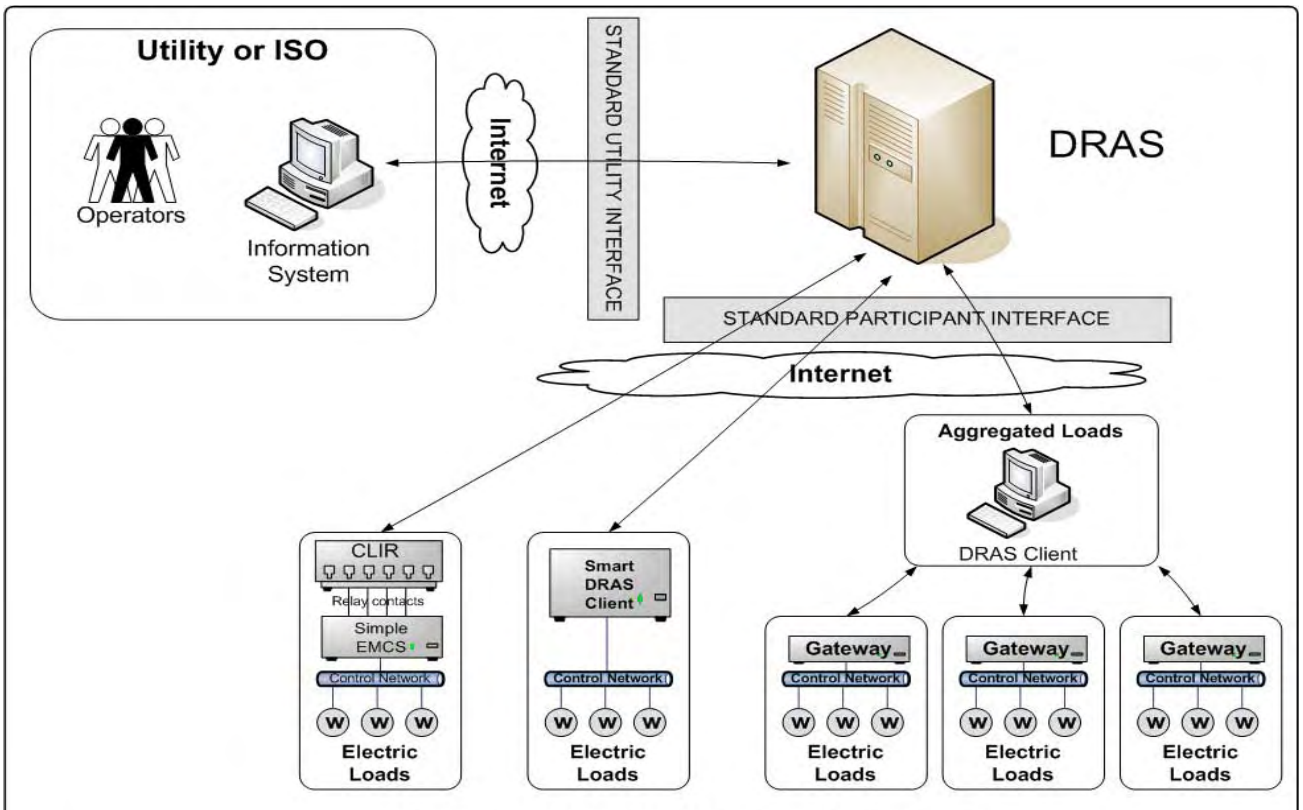

Figure 1. Automated Demand Response

DR events from the Utility/ISO which are normally handled by human operators. The main concept of Auto-DR is to remove the humans from the loop as much as possible and thus automating the actions within the facilities. The DRAS accomplishes this by brokering the communications between the Utility/ISO and the equipment in the facilities. This is depicted in the Automated DR event notification is shown in the use case diagram of Figure 2.

In addition to specific DR events the DRAS is also designed to handle Real Time Pricing (RTP) streams from the Utility and potentially convert these into DR events for the facility to act upon.

Note that a number of ancillary operations are also performed in support of DR Event notifications including configuration, operations and reports. The DRAS also support these activities although they are not described in detail in this paper.

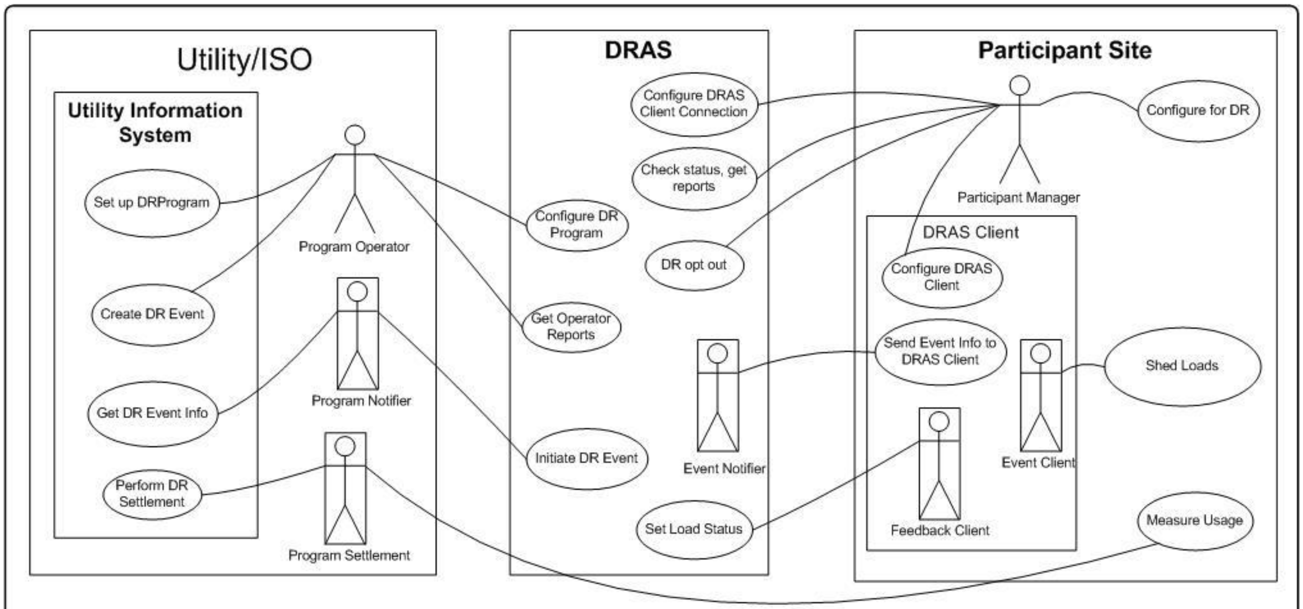

Figure 2. DR Event Notification Use Case

The sequence of operations that take place when a DR event is issued by the Utility/ISO is the following:

1. Utility Program Operator creates DR Event in Utility Information System.
2. Utility Program Notifier gets DR Event information from Utility Information System. (date and time) and initiates DR event in DRAS
3. Event Notifier in DRAS sends event info to all DRAS clients in DR program.
4. DRAS Event Client in Facility sends event info to Client sub-systems resulting in the shedding of loads.
5. DRAS Feedback Client in Facility sets load status in DRAS (e.g. shed status information).
6. Utility Program Settlement measures usage in Client Sites and performs settlement in Utility Information System.

2.2. Automated Bid Submissions

Some DR programs require that Participants submit bids for available shed resources. The Utility/ISO will then either accept or reject those bids and those that are accepted will receive subsequent DR Event notifications to perform the actual sheds. The submission of bids is yet another DR related activity that requires a human in the loop and is thus a candidate for further automation.

Experience has shown that many Participants that participate in these types of DR programs rarely change their bids from one DR Event to another. Thus the DRAS can be used to automate the submission of bids by using the concept of a "standing bid". Standing bids can be programmed into the DRAS by the Participants and whenever a request for bids is issued by the Utility/ISO the standing bids can be submitted by the DRAS at the appropriate time. Figure 3 shows the use case diagram for automating the submission of standing bids by Participants.

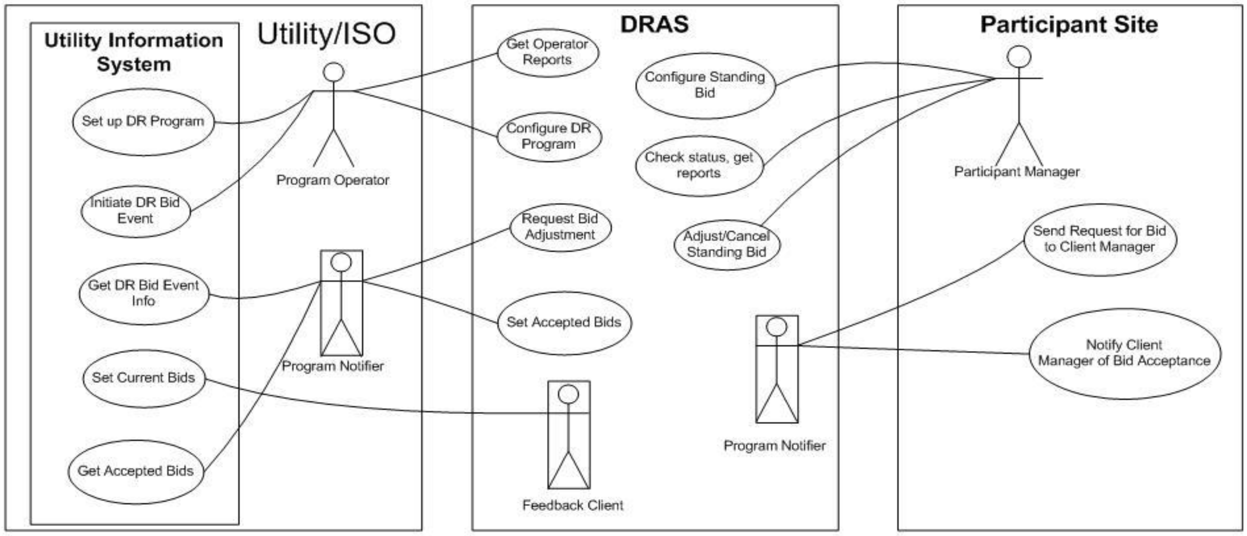

Figure 3. Automated Bidding

The sequence of steps used to perform automated bid submissions are the following:

1. Utility Program Operator initiates Bid Event in Utility Information System.
2. Utility Program Notifier gets bid event information from Utility Information System. (date and time) and initiates a request for Bid adjustment in DRAS (request for bids)
3. DRAS Program Notifier sends request for bid to the Participant Manager
4. Participant Manager Adjusts/Cancels current bid in DRAS (optional).
5. After specified time limit the Bidding Proxy in DRAS sets the current bid in the Utility Information System.
6. Utility Program Notifier gets accepted bids from Utility Information System and sets accepted bids in DRAS
7. DRAS Program Notifier sends the acceptance notification to the Client Manager

3. DRAS OPEN INTERFACE STANDARDIZATION

A standard for the various DRAS interfaces would have the benefits of lowering the effort and cost of implementing Auto-DR programs and thus increase the level and reliability of participation in them.

In 2007 the DRRC began a standardization effort by bringing together a consortium of industry stake holders primarily composed of the major Utilities and ISO in California. In addition other research and standards organizations such as the California Energy Commission (CEC), Electric Power Research Institute (EPRI), Building Automaton Control Network (BACnet), National Institute for Standards and Testing (NIST), and Open Home Automation Network (OpenHAN) are participating in the effort.

The standardization effort is relying heavily upon the lessons learned since 2002 in implementing Auto-DR programs in California. The objective is to have an initial draft of the standard by early 2008 that can form the basis of a DRAS implementation that can be used in the DR programs that will be made available in the summer of 2008. It is anticipated that the standard produced by this industry consortium may eventually be submitted to a standards organization such as IEEE (Institute of Electrical and Electronics Engineers, Inc.) or ASHRAE (American Society of Heating, Refrigeration, and Air conditioning Engineers) to become an official standard.

3.1. DRAS Requirements

The following are some of the general requirements of the DRAS:

1. Communications with the DRAS should use readily available and existing networks such as the internet.
2. The DRAS interfaces should be platform independent and leverage existing standards such as XML and Web Services.

3. The DRAS communications should use a security policy that enables both the authentication and the encryption of the communications with the DRAS.
4. The DRAS should support communications with a variety of control systems that may range from a very simple EMCS to those with sophisticated data processing and programming capabilities.
5. The DRAS should not be dependent on specific control systems within the facilities.
6. DRAS Clients that communicate with the DRAS should easily integrate with existing facility networks and IT infrastructures.
7. The DRAS should support aggregated loads that may be managed by third party aggregators.
8. Reconciliation of DR Event participation is outside the scope of the DRAS. There are a number of methods such as aggregators, AMI, etc. that can and will handle the measurement of sheds for the purposes of the reconciliation of DR programs.

4. ARCHITECTURE

The general architecture for handling automated DR Events is shown in Figure 4. Although not shown, the same architecture also handles the Automated Bidding functions.

The DRAS is intended to interface to two different types of DRAS clients within the Participant's facility. The first is called the "Smart DRAS Client" which is capable of receiving full DR Event information as specified by the Utility. The second is referred to as the "Simple DRAS Client" (CLIR box of Figure 1), which receives a simplified characterization of the DR Event in terms of simple levels such as normal, moderate, and high. The Simple DRAS Client is intended to be used in environments where there is not a sophisticated EMCS that can be easily programmed. In this case the Simple DRAS Client can be nothing more than a gateway with simple relay contacts that interface to an existing EMCS.

Furthermore the interface with the DRAS Client is intended to support both a PUSH and PULL model of interaction. In the PULL model the DRAS Client polls the DRAS for information while in the PUSH model the DRAS asynchronously sends information to the DRAS Client. The PULL model has the benefit of being easier to integrate with existing IT infrastructures because of firewall issues and security certificates. The PUSH model has the benefit of reduced latency and network activity.

As shown in Figure 4 Real Time Pricing (RTP) is depicted as being supported in the DRAS. It is anticipated that in the case of Smart DRAS Clients the RTP information is sent directly to the DRAS Clients when it is received. In the case of Simple DRAS Clients there will be a set of rules configured in the DRAS that converts RTP information to the simple level information that the Simple DRAS Clients require.

Note that the user interface is depicted as being outside the DRAS. It may be that for a particular implementation of the DRAS a web based UI may be part of the DRAS, but the look and feel of the UI to the DRAS is considered outside the scope of the standard.

In Figure 4 the DRAS is depicted as a stand alone component, but it should be understood that the DRAS may be integrated with the Utility/ISO or the Participants information systems.

5. CONCLUSION

The DRAS plays an important role in automating DR programs and has proven its worth over a number of years in both research and actual commercial environments at LBNL and the big three IOU's in California.

Because its functionality has been focused on removing the human from the loop its scope is relative narrow and thus easily integrated with existing infrastructures and operations on both the Utility/ISO and the Participants side of the equation.

With the development of standard interfaces to the DRAS it is hoped that the architecture will become even more widespread and there will be the development of more DRAS clients that will enable a wider range of facilities to leverage the benefits of DR.

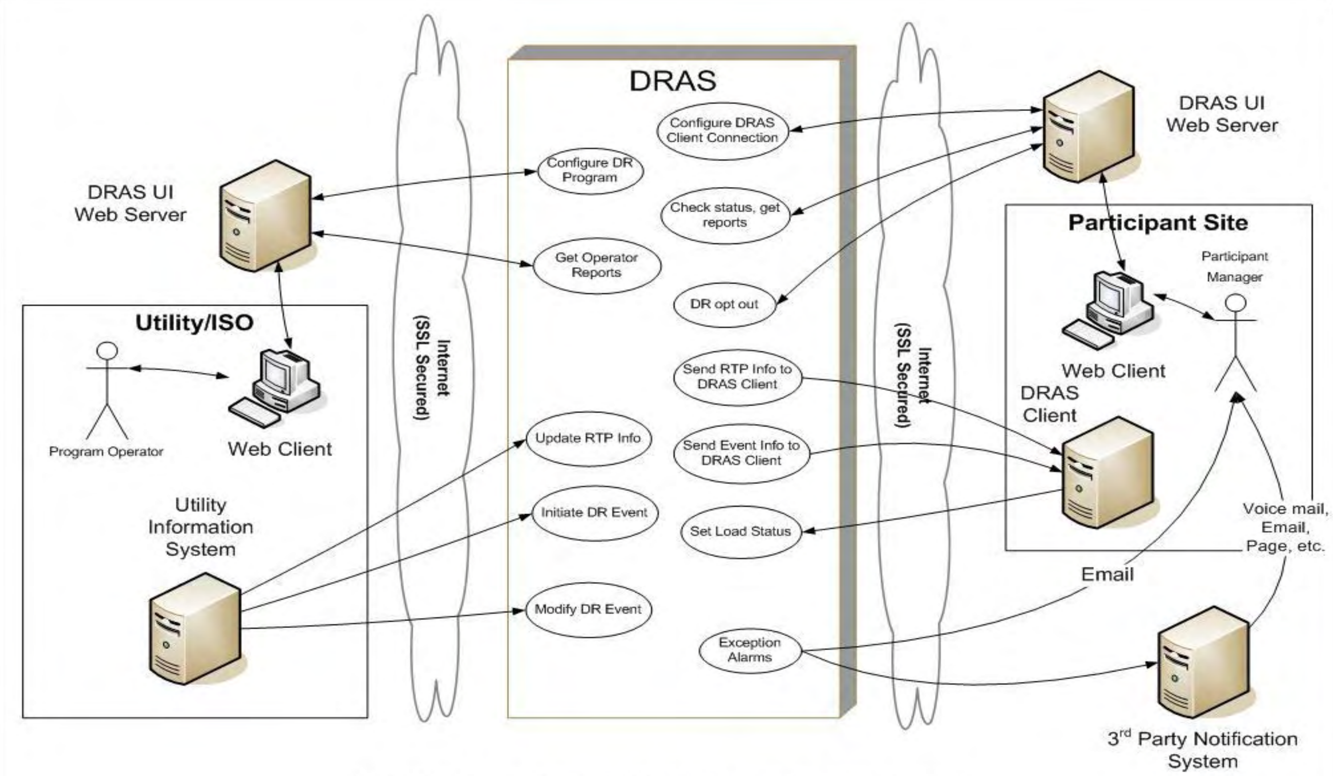

Figure 4. Automated DR Events Architecture

6. ACKNOWLEDGEMENTS

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Biography

Ed Koch is founder and CTO of Akuacom. Akuacom specializes in enterprise systems for automated energy control and monitoring in commercial and residential buildings, especially as it applies to Demand Response Programs. Prior to that Ed was the founder and CTO of Coactive Networks which specialized in creating solutions for linking distributed control networks used in energy management systems to IP networks and enterprise applications.

Mary Ann Piette is a Staff Scientist at Lawrence Berkeley National Laboratory and the Research Director of the PIER Demand Response Research Center. She has at LBNL since 1983 and has extensive experience evaluating the performance of energy efficiency and demand response in large facilities. The DRRC is a 3-year old Center to plan, manage, conduct and disseminate DR research for the California Energy Commission. Ms. Piette has a BA in Physcial Science and a MS Degree in Mechanical Engineering from UC Berkeley and a Licentiate from the Chalmers University of Technology in Gothenburg, Sweden.

Integrated, Agent-Based, Real-time Control Systems for Transmission and Distribution Networks

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Keywords: Agent-based control, interoperability, special protection schemes, distribution circuit reconfiguration, distributed generation

Abstract

Centralized control systems can be easier to design and generally conform to utility industry practices, but have disadvantages in terms of actuation speed and limited robustness to failures. Interoperability among devices and across systems will facilitate decentralized decision-making systems that can react quickly to local problems and, when well designed, are more resilient to failures. This paper describes a conceptual design for the integrated, real-time control of both transmission and distribution systems. The design uses intelligent control agents located at nodes in the grid. To illustrate the utility of decentralized, agent-based, real-time control, we describe two agent-based control algorithms, one designed to mitigate the effects of cascading failures in the transmission system and the other designed to improve distribution circuit performance. After describing the proposed design concepts and presenting some example results, we describe some information technology advances that have the potential to enable an interoperable network of software agents with real-time control capabilities for both transmission and distribution.

1. INTRODUCTION

In most utility systems, the power delivery control system has two components, (1) centrally located operators (human and computerized) who schedule resources along long time horizons, and (2) decentralized protection devices that react quickly to local stress by disconnecting equipment. As information technology improves, it is possible to increase the intelligence and communications bandwidth of the decentralized devices, and decrease the reaction time of centrally managed control systems. Decentralized systems are getting smarter and centralized schemes are getting faster.

Such advances do not come too soon for the electricity industry. Open-access rules and market restructuring generally increase demand for transmission capacity, putting more stress on the existing infrastructure. When transmission networks become overly stressed, cascading failures become ever more likely [1,2]. Some have proposed that massive investment in transmission infrastructure is needed [3], but siting new transmission lines is extremely difficult [4]. The industry will likely need to use the existing transmission infrastructure more judiciously to meet the increasing demand for long-distance power transmission. When employed correctly, information technology can help the electricity industry to use existing assets more effectively by bridging the gap between fast decentralized devices and slow centrally-located operators.

A number of technologies have been proposed to fill this gap. Many utilities operate Special Protection, or Remedial Action, Schemes (SPS or RAS) in which a control system is designed to react to extreme events by quickly enacting pre-determined sets of control actions—typically demand and generation reduction. Industry experience with SPS is mixed [5].

In addition, the architecture of the power delivery system is likely to substantively change as distributed energy resources (DER) and intermittent renewable energy sources become significant contributors to the energy supply mix. One benefit of a DER unit is the ability to supply a small section of the grid with power when the bulk power system endures a blackout. But without careful design, network reconfiguration algorithms will not reliably enable islanded operations when needed. While dynamic islanding is beneficial, DER units and other devices in a distribution circuit have the potential to provide even greater benefits to reliability and system economics when they can work cooperatively with the high-voltage system. For example, when appropriately scheduled, a DER unit can substantially reduce losses and improve the voltage profile on a circuit. In order to realize these benefits, the industry needs an agreed-upon architecture for interoperable transmission and distribution control systems.

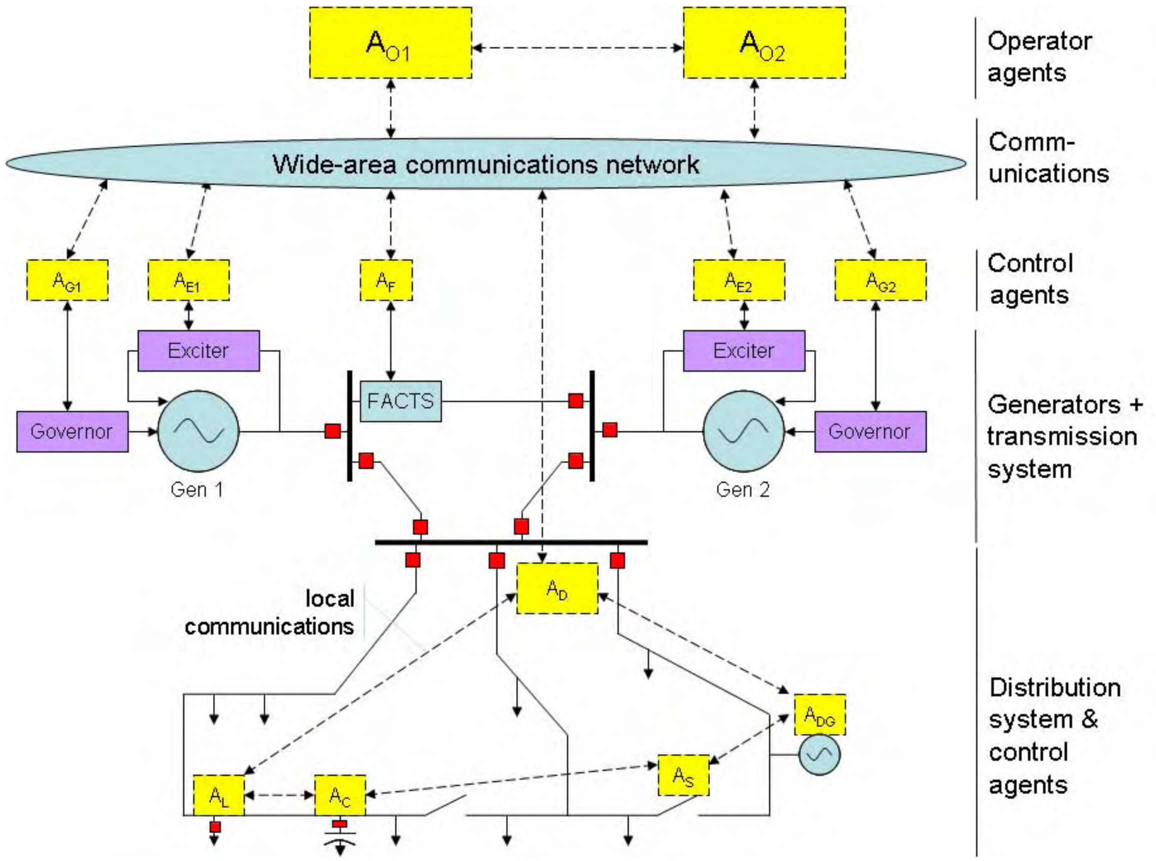

Figure 1—An illustration of the architecture for interoperable transmission and distribution control agents, as proposed in this paper. Each agent is co-located with its actuator/device. The following agents and devices are shown: A_G–generator, A_E–exciter, A_F–FACTS device, A_D–distribution substation manager-agent, A_L–load control agent, A_C–capacitor-bank, A_S–switch or interrupter, A_{DG}–distributed generator.

With these challenges in mind, this paper describes the conceptual design, and some illustrative design details, for a network of software agents with the ability to implement many real-time control tasks that require more intelligence than simple protection but are sufficiently time-critical to make a centralized implementation impractical. Section 2 describes the proposed design at a conceptual level and provides a short review of similar designs from industry and academia. Sections 3 and 4 describe illustrative designs and results for agent-based transmission and distribution control systems. Section 5 describes some of the communications infrastructure challenges associated with this design, focusing particularly on strategies for interoperability. Finally, Section 6 draws some conclusions.

2. CONCEPTUAL DESIGN

Power systems are complex large-scale interconnected systems that have a variety of actuators with different objectives and time responses. The coordination of sensors and actuators is a formidable task. Most of the existing actuators take local actions based on local information only. Such actions cannot, in general, guarantee that the devices will act according to system-wide performance goals. However, advances in communication and computation technology can facilitate better coordination amongst the thousands of devices in a power system.

In the conceptual design illustrated in Figure 1, one control-agent is located at each actuator in both the transmission and distribution networks. Each agent is responsible to gather local measurements and choose set-points for its local device. During normal operations, when time-critical adjustments are not necessary, the agents coordinate their decisions with operator-agents, both human and computerized. When decisions must be made quickly and operator intervention is impractical, the agents work with other agents in their neighborhoods and choose actions according to agreed-upon goals and methods.

The result is a multi-layered architecture for coordinated real-time transmission and distribution system operations. Section 2.1 describes how these concepts fit with current developments at Southern California Edison (SCE). Sections 2.2-2.4 describe some additional details of the conceptual design described here.

2.1. Transmission and distribution system coordination at Southern California Edison

Traditionally, SCE has planned and operated its distribution, sub-transmission and transmission systems as relatively independent systems. Three planning/operating practices at SCE illustrate this intentional independence among system levels, reactive power (VAR) planning, radialized sub-transmission, and independent remedial action schemes (RAS). Following a brief discussion description of these practices is a discussion of several emerging practices that will require an understanding and integration of the concepts of interoperability.

2.1.1. Reactive power (VAR) planning

SCE's VAR planning standards require that no net VAR transfers take place between the transmission, subtransmission and distribution systems.

2.1.2. Radial sub-transmission

Under SCE historical practice transmission, sub-transmission (66 kV and 115 kV) and distribution systems generally operate separately—sub-systems cannot rely on one another for reactive power or other secondary support beyond maintaining a delivery chain from source to load. Few mechanisms exist for coordinating resources between these sub-systems. Consequently each sub-transmission system has a single interface with the bulk networked transmission system (220 kV and 500 kV), and each distribution circuit maintains one interface with the upstream sub-transmission system. This results in numerous radial configurations. A radial design ensures that "N-1" outages in the bulk system do not generally trigger parallel flows through the lower-voltage circuits. On the other hand, radial design generally means that more power system infrastructure is required to meet NERC/WECC requirements for serving load after "N-1" outages.

2.1.3. Independent Remedial Action Schemes (RAS)

SCE has designed its RASs so that each scheme is independent. This practice simplifies design and implementation, but may limit the potential to draw benefits from coordinated Remedial Action Schemes.

2.1.4. Future developments

The three practices described above demonstrate a conservative approach, which may limit the potential to leverage existing infrastructure for wide-area system benefit and increased efficiency. Looking forward, SCE is currently exploring other operating procedures such as: automated capacitor control schemes with a hierarchical design across voltages, a centralized RAS that could choose among systems/assets for maximum system-wide benefit and the use of locally installed resources to support system services. Furthermore, SCE initiatives closer to the consumer, specifically SCE's SmartConnect™ advanced meter initiative, will provide additional future opportunities to expand interoperability and advanced decentralized controls schemes for system, and ultimately, customer benefit.

Improvements in and growing deployment of measurement/sensing, communications and data processing technology will facilitate opportunities to develop and deploy systems and procedures that support one another.

The concepts discussed and illustrated in this paper will inform and support these emerging efforts at SCE.

2.2. Goals

Power systems operate with many goals (objective functions to be minimized or maximized and constraints to be satisfied). Among these are economic goals, reliability goals and environmental goals. While operators can manage tradeoffs among these goals along slow time-horizons, it is the responsibility of automated control systems (control agents) to manage these when action by human operators is not practical. The following are some of the goals that are particularly important during time-critical operations:

1. Minimize the cost of serving existing load.
2. Minimize the cost of control actions (wear and tear on or damage to equipment).
3. When it is not possible to serve the entire existing load, then the goal becomes that of serving as much load as possible, perhaps weighted by relative priority among loads.
4. Maintain the system voltage profile as close as possible to an operator-defined goal profile.

During normal operations, these goals can typically be managed by human operators, with some assistance by centrally located computer systems. During stressed conditions, when delayed action could result in a massive blackout, these goals are best managed by software or hardware agents that are closer to the problems. While these goals are generally agreed to be important, setting priorities among these (and others goals not yet identified) is an important part of the design of such software systems.

2.3. Coordination methods

Many methods exist for coordinating the actions of agents. Among these are: voting schemes in which agents agree to enact the most popular action, hierarchies in which low-level agents act according to the goals of higher-level agents, and decentralized optimization methods. The algorithm described in Section 3 is based on decentralized optimization. The algorithm in Section 4, in its current form, is essentially hierarchical.

2.4. Related programs and literature

Through programs like the GridWise™ [6,7], EPRI Intelligrid [8], the CIM working group [9] and the Modern

Grid Initiative [10] the US electricity industry is making some progress on standards and designs for communications among devices in the power grid. These programs provide substantial guidance information to utilities who would like to upgrade their communications infrastructure, metering and devices. The programs provide lesser guidance for coordinating the actions of these devices to meet various control goals.

Some designs from equipment manufacturers and academia provide some guidance in this area. While a full review of existing technologies and designs is beyond the scope of this paper, [11,12] describe algorithms and conceptual designs that are in many ways related to the ideas in this paper.

3. AGENTS FOR TRANSMISSION SYSTEM EMERGENCY CONTROL

This section describes a method for coordinating emergency load shedding, governor and exciter controls to restore voltages and currents to acceptable levels before a large blackout results. High currents and low voltages often result from disturbances to the power system, such as transmission line or generator outages. When these persist, relays often act to protect equipment from damage. This can push the stress to other portions of the grid, with the result being a string of component outages known as a cascading failure. Large cascading failures, such as the Aug. 14, 2003 blackout in North America, can have enormous social costs. The method, which is described briefly here and in detail in [13], is designed to minimize these social costs associated with blackouts by quickly arresting the spread of cascading failures through load shedding and generator controls.

3.1. The global transmission control problem

The problem of minimizing the social costs of cascading failures can be written as a set of goals (objectives and constraints) that need to be met over a time horizon. More specifically, the following goals are relevant to the cascading failure problem:

1. Minimize cascading failure risk by keeping branch currents below, and voltages above, high-risk thresholds.
2. Minimize the cost of remedial control actions by enacting minimal emergency load shedding and adjustments to generator set-points (governor and exciter).

When currents or voltages are beyond their thresholds, these goals can come into conflict. In order to resolve this conflict, the above goals are re-written as a single objective Model Predictive Control (MPC) [14] problem with the following form:

$$\begin{aligned}
&\underset{\Delta\mathbf{P}_G,\Delta\mathbf{P}_D,\Delta|\mathbf{V}_G|}{\text{Minimize}} && \sum_{k=0}^{K-1}\rho^k \;\; \text{Cost}(\Delta\mathbf{P}_{G,k},\Delta\mathbf{P}_{D.k},\Delta|\mathbf{V}_{G,k}|)+\text{Risk}(|\mathbf{V}_k|,|\mathbf{I}_k|) \\
& && |\mathbf{I}_{k+1}|=|\mathbf{I}_k|+f(\Delta\mathbf{P}_{G,k},\Delta\mathbf{P}_{D.k},\Delta|\mathbf{V}_{G,k}|) \\
&\text{Subject To} && |\mathbf{V}_{k+1}|=|\mathbf{V}_k|+g(\Delta\mathbf{P}_{G,k},\Delta\mathbf{P}_{D.k},\Delta|\mathbf{V}_{G,k}|) \\
& && \Delta\mathbf{P}_{G,k},\Delta\mathbf{P}_{D.k},\Delta|\mathbf{V}_{G,k}|\in\text{Feasible}_k
\end{aligned}$$

where ρ^k is a discount factor for each time step in the time horizon t_0, t_1,…, t_K, $|\mathbf{V}|$ and $|\mathbf{I}|$ are vectors of voltage and current magnitudes, $\Delta\mathbf{P}_G$ and $\Delta\mathbf{V}_G$ are vectors of changes to the governor and exciter set points and $\Delta\mathbf{P}_D$ is the amount of demand reduction required. f and g are linear functions that translate changes to the control variables to changes in branch currents and bus voltages. The functions “Cost(…)” and “Risk(…)” evaluate the cost of emergency controls and the risk of allowing high voltages and low currents to persist. The result is a linear programming problem that can be used to calculate emergency control actions quickly, even for systems with thousands of busses. But the amount of input data required to set up the problem initially is large, requiring a full set of voltages and currents for the system at run time. Unfortunately most centrally located operators are not able to collect these data fast enough to enact such a scheme. State estimation alone can take tens of seconds to minutes. A decentralized solution, where control actions are calculated and implemented by agents located at substations, has the potential to act more quickly.

3.2. Solving the transmission control problem with agents located at substations

In the decentralized approach to the cascading failure problem, we place a control agent at each substation in a power network. Each agent is given an initial skeleton model of the power network, with all voltages at 1.0 p.u. and all currents at 0A. During normal operations, the agents talk with their neighbors to collect enough data to build rough models of the network that surrounds them. These models are fairly accurate for their immediate neighborhoods and less so for more remote locations (see Figure 2). When an agent becomes aware of a voltage or current violation, it shares the data with its neighbors and chooses a set of control actions (both local actions and estimates of what its neighbors should do) given its model of the network. It then exchanges information with agents that appear to need to take emergency controls, tries to form consensus on these emergency actions, and implements these controls. After the agents take new measurements, the process repeats until all known violations are removed (see [13] for details).

3.3. Experimental results

In order to test the method described above we created 100 large cascading failures and measured blackout sizes in each of three cases: (1) no emergency control, (2) centralized MPC with perfect information and (3) agent-based MPC. In case (1) the cascading failures propagate through over-current relays and under-frequency load shedding. In case (2) supplementary control is provided by an omniscient agent that can measure every value in the network and control every device in the network. This provides a lower bound for cascading failure size in each case. In case (3), agents with imperfect information work to control each cascade. Figure 3 shows the distribution of cascading failure sizes for case. The MPC agents do not perform as well as an omniscient agent, but the performance reduction is small. In both cases, the average blackout size is reduced by nearly an order of magnitude relative to the base case.

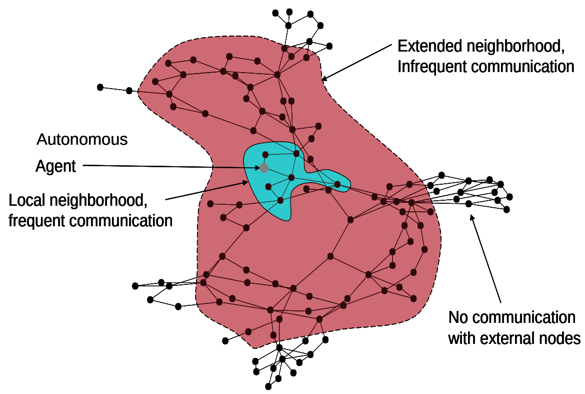

Figure 2–An illustration of one agent's perspective of the transmission system. Each agent communicates regularly (once per second) within its local neighborhood and periodically (once per day) with extended neighbors.

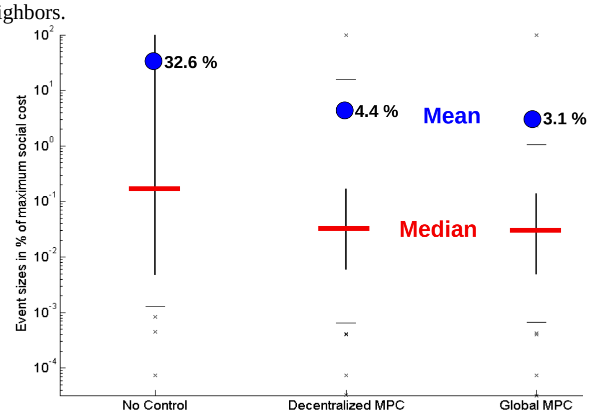

Figure 3 – The distribution of simulated cascading failure sizes without control (left), with an omniscient control agents (right) and with substation control agents (middle). While the agents, who work with imperfect information, do not perform as well as the global algorithm, the performance reduction is small.

4. DISTRIBUTION CIRCUIT CONTROL AGENTS

In our second example design, we use a network of control agents to control voltages and perform restoration within a distribution circuit. Specifically this design is based upon the following goals:

1. Ensure that voltages are as close as possible to an operator defined goal profile (typically 1.0 p.u.).
2. Keep currents below overload thresholds.
3. Serve as much of the existing demand as possible, taking into consideration possibly weighted by the relative importance of different loads.
4. Ensure that the circuit configuration is radial after control actions are complete.

The algorithm is being designed in concert with SCE's "Circuit of the Future" program. Doing so provides a real-world distribution system for the evaluation of agent-based control methods. The controlled assets on the Avanti 12 kV circuit, relevant to this analysis include: load-break switches, load-transfer switches, load-tap transformers, mechanically switched shunt capacitors, a power electronic switched multi-stage capacitor and a distributed generator. Figure 4 illustrates the devices and systems that support the operating variables and controlled operating points in the Avanti circuit.

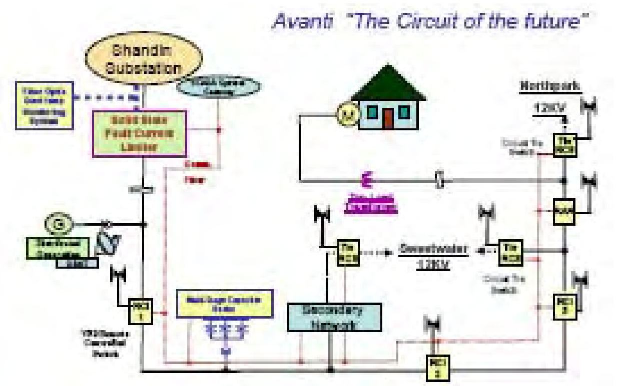

Figure 4 – Specific to interoperability, SCE's distribution Circuit of the Future project is SCE's effort to increase its own understanding of how to implement and leverage DER-enhanced grid interoperability as well as building the broader power industry's understanding too.

4.1. Distribution circuit control method

To meet the distribution circuit goals, we place one agent (A_D in Figure 1) at the distribution substation for the circuit. This agent has the responsibility to collect data from other agents in the circuit and to coordinate the control actions of other agents in the circuit. Agents are also placed at each switch and DER unit in the circuit or where controllable loads are available. These agents pass data to and enact commands from A_D. When not given any commands from A_D, an agent may use simple rules based on local information to choose control actions, roughly equivalent to what is practiced currently. For example, an agent managing a switched capacitor bank (A_C) will control the bank according to the locally measured voltage, unless it gets a command from A_D to enact controls required to satisfy higher-level goals.

As with the transmission problem, A_D formulates its goals into an MPC problem. The result is the following nonlinear, mixed integer optimization problem with the following form:

$$\underset{\mathbf{a},\mathbf{P}_G,\mathbf{Q}_G}{\text{Maximize}} \quad \sum_{k=0}^{K} \rho^k \left(\mathbf{c}_D \mathbf{P}_D{}^T - \mathbf{c}_G \mathbf{P}_G{}^T - c_V \sum_i \left| |V_i| - \overline{|V_i|} \right|^2 \right) \tag{3.1}$$

$$\text{Subject To} \quad \text{PowerFlow}(\mathbf{S}_{G,k}, \mathbf{S}_{D,k}, \mathbf{V}_k, \mathbf{I}_k, \mathbf{a}) = 0 \tag{3.2}$$

$$|\mathbf{I}_k| \le |\mathbf{I}|_{\max} \tag{3.3}$$

$$\sum_{b \in L_i} (1 - a_{b,K}) \ge 0, \ \forall L_i \in \text{CircuitLoops} \tag{3.4}$$

where $\mathbf{S}_D=\mathbf{P}_D+j\mathbf{Q}_D$ and $\mathbf{S}_G=\mathbf{P}_G+j\mathbf{Q}_G$ are complex vectors representing the actual demand served and the actual generator outputs, including the generation supplied by the bulk system at the transmission substation, **a** is a vector of switch positions in the circuit, and $\mathbf{c}_D$, $\mathbf{c}_G$ and $\mathbf{c}_V$ are cost vectors indicating the value of demand served, generator supplies and voltage profile error respectively. Eq. 3.2 represents the AC power flow equality constraints, accounting for the effects of the switch variables (**a**). Eq. 3.3 gives the current limits in the circuit, and Eq. 3.4 enforces the constraint that the circuit must be radial at the final time period. When solved, the problem outputs a sequence of control actions (changes to switches and generators primarily) that are feasible and meet the circuit's goals. After calculating a control plan in this way, A_D will send commands to the switch and DER agents to enact the controls.

Clearly, this hierarchical approach is fairly simple, and relies on the correct operation of A_D to a large extent. In future work, we will study more sophisticated approaches to coordinating the agents' control actions.

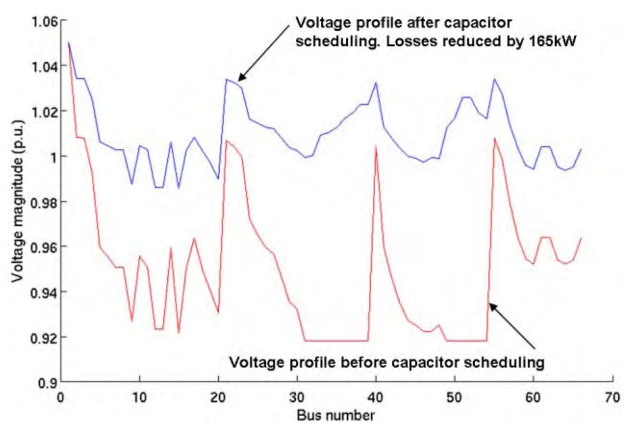

Figure 5—The voltage profile in the SCE circuit, with 24 MW of demand, before and after capacitor switching according to the problem formulation in Eqs. 3.1-3.4.

4.2. Example results from capacitor scheduling

To illustrate the utility of this problem formulation, Figure 5 shows the voltage profile of the SCE circuit before and after scheduling the switched shunt capacitors in the circuit according to the problem formulation described above. By including both the voltage profile and loss minimization in the objective function, we were able to make significant improvements in both dimensions of the problem through appropriate capacitor switching. In future work we will extend these results to the reconfiguration problem, refine the algorithm and work on ways to decompose these two problems among the substation agent and agents located at the actuators (switches, capacitors, etc.).

5. INTEROPERABILITY

If the electricity industry is to achieve the vision of integrated, coordinated transmission and distribution systems control, it will need to develop standards that allow agents in the network to communicate clearly and efficiently. In the computer and software industries, substantial progress has been made in this area through the design of open standards for storing and sharing information. Such "Open Systems" are designed to avoid any proprietary interfaces and protocols, adhering instead to open standards. Several standards for data exchange among devices at the substation level and for SCADA applications have emerged in recent years. The following is a brief discussion of some of these.

5.1. Standards for power system communications

The growing number of intelligent electronic devices within substations and electric distribution and transmission systems has prompted several efforts aimed at developing open communications protocols for T&D equipment [15]. The IEC 61850 standard [16] defines a model for intra-substation communications for both real-time and non real-time communication and incorporates ideas developed within the Utility Communication Architecture (UCA, [17]) 2.0 efforts. The IEC 60870-5 series defines a protocol for substation to control center communication and has specific extensions for use over wide-area networks. The Distributed Network Protocol (DNP, [18,19]) is another communications protocol for both intra-substation and substation to central/utility and is based in part on the IEC 60870-5 series. All of these standards were developed to unify the many protocols used by T&D and automation equipment venders.

In addition to protocols for the exchange of data, agents need standards to ensure that the data itself is clearly defined. Most current data-description standards are based upon XML (extensible markup language) standards. One XML project for T&D data is based on the Common Information Model (CIM, [9]) through IEC Technical Committee 57. CIM allows abstracting and representing all major power system objects needed for power flow topology models, energy management systems, and data management systems, and is a continuation of EPRI's Control Center API (CCAPI) efforts. Standards for distribution system data, within CIM, are still in progress.

Work is also being conducted to unify the IEC 61850 object models with those associated with CIM.

Additional work is being done under the UCA International Users Group in the area of standards for automated metering and demand response. This users group has subgroups covering IEC 61850, CIM and OpenAMI. As more utilities start to implement advanced metering systems that incorporate customer demand response, monitoring and control can be exercised down to the specific customer level. Capabilities are being developed that would allow 2-way communications all the way from the utility to the customer. This would include a link to the customer thermostat to allow control of thermostats.

Outside of the power-systems arena, the Foundation for Intelligent Physical Agents (FIPA, [20]), an IEEE Computer Society Standards Organization, has established standards for both agent design and communications protocols. FIPA provides a general framework for agent communication languages (ACL). The work here will extend the vocabulary and ontology in the FIPA standards by building on concepts and terminology established by CIM. Once the ACL components have been defined, other agents with different design goals can be easily integrated into the resulting multi-agent system, facilitating interoperability through and open design.

5.1.1. The limits of current technology and data-exchange practices

While the ideal communications system would allow peer-to-peer communications between any two system components, in reality most utility communications systems only allow this communication to take place at the system "head-end" or central database. Most utilities have different communications systems for each type of automation (transmission SCADA, substation automation, distribution automation, load control, meter reading). Given current technology, if a smart agent needs data from more than one system, it would have to get it from the system's central databases. This communication structure might limit the capabilities of agents that need to act quickly to using only data from within one communications system. Communications requiring more detailed data from other central databases would need to be obtained in a slower manner and used to establish local operation goals for the agents.

5.2. Benefits of interoperability

Interoperability, or the capability of different components of a circuit to work together effectively with little or no human interaction, is vital to the effective use of the grid [21]. Interoperability requires components to be connected to each other using both hardware and software. Once this connection is complete, components can interact with little to no human input.

To be implemented, interoperability has three fields that need to be addressed: technical, informational, and organizational.

Technical interoperability involves the physical and communicative connectivity between actual devices. The devices must have a common protocol in order to interface with each other regardless of component brand, manufacturer, etc. Informational interoperability pertains to the content and format for data or instructions. Organizational interoperability means that the businesses involved have compatible processes and procedures. All parties must address their business, economic, and legal relationships among themselves to ensure organizational interoperability works. These three elements are all required for an effective implementation of interoperability [22]. In other words, interoperability is achieved when users can easily exchange and use information among various devices from different providers.

The GridWise Architecture Council (GWAC) provides a forum and framework that will help the electric utility industry achieve interoperability. GWAC's mission is to establish broad industry consensus regarding the integration of advanced technology and communications into electric power operations in order to enhance our socio-economic well-being and security [23]. SCE DER's participation on GWAC provides us direct input and exposure to this exciting area of industry advancement.

SCE DER believes that many aspects of the GWAC vision are in direct alignment, not just with SCE DER's interests and needs, but with SCE and wider industry interests. The following highlights particular areas of the GWAC vision that we embrace.

GWAC's vision is to integrate interoperability with distributed energy resources. GWAC works toward this vision by establishing a framework to help identify issues and create a context that can facilitate understanding and change among those involved in the electric system. GWAC also plans to establish a consensus building process and foster cross industry segment collaboration. In this sense, GWAC acts as the "overseer" for the support and eventually the implementation of interoperability.

GWAC focuses heavily on the transformation of the power industry. Such a transformation will result from widespread adoption and use of information technology (IT) which incorporates open architecture and standards. The scope of this transformation includes the integration of new distributed technologies such as demand response, distributed generation, and storage with existing grid technology to allow for a collaborative management of the grid from power production to consumption by the ultimate customer.

We support GWAC's plan to establish a consensus building process and foster cross industry segment collaboration. In this sense, GWAC acts as the "overseer" for the support and eventually the implementation of interoperability.

Given all the technical promise from interoperability, it increases the need to address other non-technical critical factors such as benefit/cost, regulated criteria/constraints, and lack of market mechanisms to provide incentives for innovation. These factors remain open as challenges to be addressed, if the industry is to actually realize the technical potential illustrated in our paper.

6. CONCLUSIONS

Advances in information technology have the potential to facilitate substantial improvements in T&D real-time operations. It is increasingly possible for the components of the T&D system to solve very difficult problems in real time, without needing to consult centrally located control centers. An agent-based design for coordinated real-time T&D control could bridge the gap between simple devices, such as relays, that use only local information to make quick decisions, and operator-based controls that require a lot of information and act along longer time horizons. While the concepts and results described in this paper are far from complete, they hopefully provide some guidance for the industry as it develops plans for future real-time control methods. Before any of this technology can be implemented, the industry needs widely agreed upon standards for data and communications protocols—for interoperability.

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The Data Management Challenge:

Making Extremely Large Amounts of Data Useful and Actionable

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Abstract
The introduction of AMI has created a data paradox. Traditional AMR solutions built with relational database products are, for the most part, not equipped to perform the real-time processes needed for the future growth of AMI and SmartGrid applications nor are they capable of collection and dissemination of historical data at its original resolution. Yet the promises of AMI will only come from elimination of data latency and the ability to maintain all data at its original resolution. A new approach needs to be taken by viewing the AMI from an operational perspective as well as billing perspective. Products that have supported real-time use of data from electrical networks worldwide are now poised to become the Operational Data Managers in the new AMI and will deliver on the promise of closer ties between market price signals and customer usage of electricity.

Industry History – Supply-Side
Throughout the 100+ year history of the electric power industry distribution systems have suffered from a lack of clear information about the state of the network. As independent utility companies grew, they interconnected with neighboring utilities to provide a modest amount of system stability to their otherwise vertically integrated operations. These connections were initially relatively weak and relied upon primarily for regional power exchanges caused by seasonal variations in demand and availability of generation resources. Since deregulation of the industry and separation of vertically integrated utility business units, the dependence upon a tightly integrated transmission grid has become a major issue. The lack of network capacity in many regions has lead to extreme price fluctuation and rapid rate increases for captive consumers.

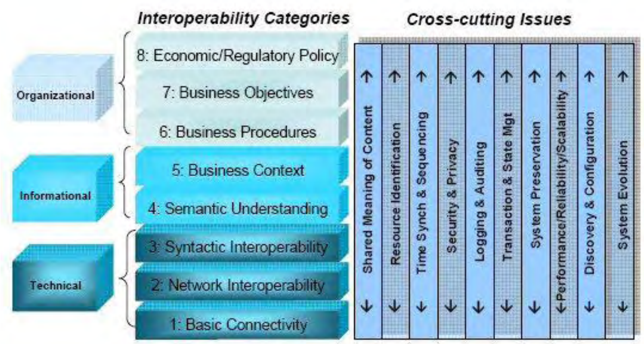
Industry Future - Demand-Side
Another alternative to the expensive proposition of supply side expansion and improvement has emerged to complement this strategy. Demand side initiatives coupled with vast improvements in communications capabilities have brought about a significant opportunity in the industry. While transmission engineers and operators have had the ability to view and control the transmission network from end to end for many years, distribution operations have not had this ability. Generally speaking, distribution is a "black box" operation with very little known about the detailed consumption habits of the millions of small residential and commercial users of electricity. Engineers and operators generally know the demand on the circuit breakers at the distribution substations but have no visibility into the minute to minute consumption of electricity beyond the substation fence. Furthermore, the disconnect between price signals and consumption has created an economic crisis for utilities who are limited by regulation on the prices they can charge yet have obligations to serve customers in a volatile market. Utilities need a more immediate connection between electricity demand and price signals to the end consumers in order to change consumption habits. Traditional utility billing systems rely on highly aggregated data to perform monthly billing. When the industry was composed of vertical utilities which owned their generation sources and sold to captive regional customers in their territory, monthly billing was adequate and easily accommodated the very steady prices for company owned generation. The volatility in electric prices introduced by deregulation and decoupling of generation sources from load serving entities has created a huge need to send immediate price signals to consumers as a means to alter customer usage habits and stabilize electric rates. The uproar created by vast regional service interruptions and volatile electric rates coupled with growth in electric demand has created a tipping point where "business as usual" is not a viable option.

Advanced Metering Infrastructure (AMI)
AMI has emerged as the likely solution for demand-side management and offers a host of new possibilities for appropriate utility rate structures, new consumer services, and price stability. As vendors rush into this new market offering a variety of technologies, utilities are faced with tough decisions about what they need, who should supply them, and whether the solutions they choose can scale and be expanded to support future customer service offerings.
Advancements in communications, availability of broadband, high speed networks and advanced digital

metering technologies provide a means to eliminate the price/use disconnect, provide consumers and utilities with a mechanism to intelligently moderate demand during periods of high electric prices and effectively let natural market economics reshape the demand curve for electricity consumption. The future of electricity consumption will be a smart home that reacts to price without customer intervention once that customer sets their "inconvenience tolerance". Management of consumption even down to individual appliances within the residence will be a common occurrence in the future Smart Grid. The opportunities (and problems) AMI introduces are complex. Many existing, repackaged AMR solutions cannot scale, suffer from data communication latency, and are not self-configuring or bi-directional. Solutions that have never before had to manage high-speed, massive volumes of distributed data were logically built using relational database designs. These products came to the marketplace from a need for aggregated data used for monthly billing purposes. They never contemplated demand-side management of electricity use, complex billing, operational uses for data or the need for long term retention of high resolution meter data, device control signals, and variable price signals. The logical approach of a relational database "billing centric" solution to more data volume has been to introduce a "clearing house" for meter data referred to as a Meter Data Management System (MDMS). Because relational databases are very good at transaction processing (like an ATM machine withdrawal) but inadequate for timeseries data management and distributed processing of events the MDMS proposes to summarize incoming data into hourly or even less granular bits of information. This eliminates any possible use of the data for operational analysis of customer usage, creates further data latency that all but makes real-time price signals moot, and creates an inflexible environment for analyzing sophisticated Time of Use (TOU) rate structures. Furthermore, data aggregation at the MDMS is done in a predefined manner which tightly couples the backend systems to whatever aggregation decisions are made today. Rate analysis using different TOU structures against historical data is rendered impossible. And the subtle changes in consumption patterns are lost in data aggregation. A fundamental shift in the utilities perspective on the problem must occur before a viable solution can be implemented. To complement the new breed of sophisticated metering and device control products being created, utilities need to look at the problem more closely from an operational point of view while retaining the ability to aggregate data for billing purposes and ensure system scalability for more complex, direct associations between customer demand and electric prices. Someday, all new real-time billing solutions will be required but a well designed data collection and dissemination solution today will allow utilities to defer investment in new billing and accounting systems while enabling phased implementation of AMI. What is needed is an Operational Data Manager.

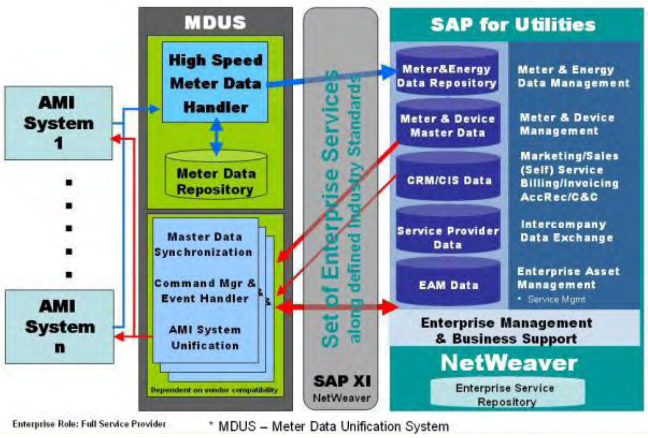
The Case for an Operational Data Manager

The Gridwise Interoperability Framework defines several cross cutting issues that in fact have been topics of conversation and system design in the real-time operations world for several years.



GridWise Interoperability Framework

Most of these issues have been addressed in an environment that is extremely time sensitive and dependent on high reliability, where decision delays or failure to deliver data would result in blackouts and significant loss of revenue. This environment is the realm of real-time operation systems. Eventually, the validation and aggregation functions of the MDMS will be dissected and moved into more appropriate parts of the meter to utility data flow to eliminate data latency and enhance flexibility and scalability. Head-end systems will become immediate data validators. Operational Data Management systems created using highly efficient, real-time solutions derived from operations oriented products will not only hold all incoming data at original resolution and maintain history on real-time metering and device control signals, but they will be device-aware and automatically accept new data when a meter is added to the AMI network, maintain history on device relationship to the distribution network, and they will tightly integrate with spatial systems (GIS) that manage the distribution assets of the utility. Back office systems will have the ability to change rate structures beyond the limited, preconfigured boundaries of a MDMS, as the utility receives approval for TOU rates. The Operational Data Manager will provide data in any aggregation the billing and accounting systems demand for any timeframe the utility wants to review. Creation of TOU rates will be based on revenue analysis using historical consumption information available at its original fidelity. Utilities will be able to make very convincing cases before their Public Utility Commissions on the positive aspects of closer coupling of price signals to consumer demand using historical consumption patterns against proposed TOU rates.



SAP's view of AMI

A marriage of technologies used traditionally for network control and real-time data management with sophisticated head-end metering and control devices will enable utilities to implement AMI in a phased in and financially manageable manner without the need for a "big bang" wholesale replacement of all back office accounting and customer billing systems in order to gain the benefits of AMI. A significant benefit from moving operational real-time solutions into the AMI space will come from better visibility into the consumption patterns (and customer response to real time price signals). For instance, distribution operators will be able to optimize networks based on data collected by the AMI system and combined with SCADA, distribution automation, capacitor control systems, equipment sensors, etc. to:

- Manage distributed generation resources;
- Maximize feeder efficiency;
- Manage circuit voltage profiles;
- Monitor grid equipment health;
- Optimize circuit loading;
- Reduce outage response times and switching analysis;
- Monitor demand response events.

As such, an Operational Data Manager must be able to manage extremely large volumes of data from a variety of sources with multiple data frequencies and latencies, including real-time. An Operational Data Manager needs to:

- Be head end system vendor and meter or demand device neutral and capable of interfacing to all device management systems
- Be scalable;
- Be highly available;
- Self discover and configure device additions and changes;
- Support aggregations and complex calculations on demand,
- Synch with other systems of record;
- Manage event data;
- Store multiple years of data online;
- Support multiple hierarchies (routes, network, asset types);
- Reconcile data with other source systems;
- Provide security and health monitoring of IT systems;
- Provide easy-to-use data access tools for a variety of users.

By combining the data collected by the Advanced Metering Infrastructure (AMI) system and SCADA, distribution automation, capacitor control systems, and equipment sensors, distribution operators will be able to optimize networks to:

- Manage distributed generation resources
- Maximize feeder efficiency
- Manage circuit voltage profiles
- Monitor grid and distribution device health
- Optimize circuit loading
- Reduce outage response times and switching analysis
- Monitor demand response events.

Requirements of an Operational Data Manager

For the intelligent grid and smart grid, an Operational Data Manager should meet a number of requirements in order to be effective for utilities' needs both today, and in the future with AMI. The features and requirements outlined below will provide a useful checklist that can be used when considering vendors for your Operational Data Manager and compliance with recommendations of the GridWise Interoperability Framework (GWIF).

Scalability
(GWIF – System Evolution)

AMR systems were originally designed to replace the manual meter reading conducted for monthly billing of retail customers. These systems and infrastructure, however, are not capable of handling readings of greater fidelity. AMI systems, on the other hand, are being designed to gather data for sophisticated new programs outside of meter reading for billing such as demand response and service reliability. These projects will include the data from large numbers of meters as well as many other real-time sensors on distribution devices.. Moving toward the intelligent and smart grid, it is estimated that there will be between six and twenty times the number of meters in terms of points to be measured—current, voltage, status, peak values, external sensors, internal devices, etc. The Operational Data Manager should make these readings and events available and actionable to the operations center in real-time to support grid management.

High Availability (GWIF – System Preservation)

AMI systems will provide the meter and device data for advanced functionality at utilities to support grid management via demand response and other data intensive applications. Many of these applications will require availability on the same par as mission critical environments like SCADA. Specifically, the Operational Data Management System will be required to respond to various equipment and telecommunications failures, security patch and operating system upgrades, and back-up of both the data and the system. These and other events will need to be performed on-line with no data loss or loss of functions. Demonstration of the high availability approach with particular emphasis on no data loss and non-stop function will be an important requirement of the Operational Data Manager.

Smart Connectors (GWIF - Discovery and Configuration)

AMI systems are extremely large. As such, it is not practical to require manual configuration of these systems, either during the initial build or for updates as changes arise. For this reason, resources within the Operational Data Manager that support all interfaces to AMI data, external data or structure must be built and maintained without requiring manual intervention. To meet these requirements, interfaces must self discover and automatically configure device additions and changes. Smart connectors are an example of this type of interface.

Meta-Data Management (GWIF – Resource Identification)

A good Operational Data Management System must have the ability to share resource definitions and configuration information with other products such as GIS. Part of the function of a Meta-Data management component of the consists of the ability to maintain procedures, relationships, models, and aliases to the AMI head-end data points. Meta-Data should be manageable from any of the integrated systems and have the ability to identify when an object is introduced to the AMI network that is not part of the network model. This concept advances Smart connectors to smart models.

Analytics (GWIF -Performance/Reliability/Scalability)

The net result of the AMI system data collection will be a stream of data that contains meter readings, events, and status messages. Extremely high volumes of events will need to be managed and processed in near realtime, with no data loss. This processing may include calculations for validation, data framing, event filtering, demand response results and notifications to support business processes, such as billing, tamper and theft, outage management and grid management. Near real-time analytical capabilities such as support for aggregations and complex calculations will be an important feature of Operational Data Managers. Descriptions of how events are managed and processed at this scale, as well as the analytical and reporting capabilities are key requirements for an Operational Data Manager.

Data Synchronization (GWIF – Time Synch and Sequencing)

Data synchronization across systems of record is an important component of the Operational Data Manager and an important requirement for an intelligent grid. AMI data will need to be reconciled and combined with SCADA, Distribution Management Systems (DMS) and other operational systems complete with audit trails. This data needs to be synchronized with systems that contain connectivity and asset information such as GIS, OMS and EAM systems. In addition, analysis of multiple versions of connectivity will be important. For example, operations may need analysis and knowledge of the system from last year's peak day as the system was switched on that day where the planning department may need to analyze the steady state system for the same time period. Operational Data Managers need to be able to provide multiple models for multiple audiences in the utility.

Data Presentation and Access (GWIF – Shared Meaning of Content and Resource Identification)

The Operational Data Manager is primarily responsible for the data stream of readings and notifications that come from meters and devices and the proper analysis and interpretation. Internally, this is a combination of the data stream traffic, results of the analytics, and any context needed to make sense out of the information. Many other utility systems will need this information in an open environment. The Operational Data Manager will need to provide data access via a Services Oriented Architecture to these other applications and support data standards such as CIM, IEC61850 and OPC.

Event Management (GWIF - Performance/Reliability/Scalability and Transaction State Management)

Many applications need to be informed by exception of changes or specific events. It is not practical for these systems to actually process the raw data stream at the rate managed by the Operational Data Manager. For example, an outage notification or "last gasp" of a meter can indicate an outage or a meter change or theft. Event management must not only identify the events for each application but also ensure that the event was actually transmitted and that the event was "real." The event management function of the Operational Data Manager must be scalable both for the number of events and the numbers of consumers of that event. This feature is critical to making real-time data useful and actionable for operations today and ultimately the management of the intelligent grid.

Historization of Data (GWIF – System Preservation)

Utilities will have higher fidelity information than has been available in the past and, in particular, data that will support operations, planning, scheduling, cap and trade certification, and other real-time functions. An often overlooked component of the Operational Data Manager is the historization of this high fidelity information. Multiple years of on-line storage and fast retrieval of this data is critical to intelligent analysis and action.

Network Support (GWIF – Security and Privacy)

Experience with AMR projects has demonstrated the importance of the health of the network and communication infrastructure. For AMI systems this importance will be compounded and with a much higher data throughput. For this reason, the Operational Data Manager should support state-of-the-art forensics and monitoring for a large scale self-healing network.

Reconciliation and Validation (GWIF – Logging & Auditing)

In addition to the real time analytics that work directly on the data stream, meter and device data must be subjected to significant *reconciliation* and *validation* to ensure what was sent out was received and to ensure readings are correct. The Operational Data Manager must have reconciliation and validation processes that are fast, reliable and flag suspect data. Tracking of any edits, changes, deletions or alteration of data must be logged in an auditable database.

High Security Installation (GWIF – Security and Privacy)

AMI systems with Home Area Network (HAN) capability will extend the reach of the utility to users (residential, commercial and industrial) and possibly make these systems a potential target for cyber terrorism security breaches. High security installations must include a system for all online application of updates from the software vendors involved (Operating System, EMS, SCADA, AMI systems, etc.). This feature should be tightly integrated with high availability.

Health Monitoring and Reporting (GWIF – Security and Privacy and Discovery & Configuration)

AMI systems may be distributed throughout a service territory which may or may not be contiguous and may or may not have dedicated, secure communications. As such, it will be necessary to provide security and health monitoring of IT systems. The Operational Data Manager should support this feature.

An Intelligent Grid and Smart Grid

It is critical to make data useable, actionable, and accessible to multiple entities internal and external to the utility when creating your path to the intelligent grid. The Operational Data Manager can serve as your one tool that adds value by combining all operational data sources together, along with meter data, even when the meter data is daily or monthly. Providing all data in a single Operational Data Manager and seamlessly accessing other systems of record provides users with a complete operational view enabling short term goals such as effective asset management and long term goals such as the intelligent grid. If implemented effectively, the Operational Data Manager can provide utilities a robust infrastructure that:

Offers extensive and flexible data collection capabilities

Provides important data management requirements such as data archiving, fast data retrieval, event management, alarming, real time SQC, scheduling, and advanced calculation, and Enables intelligent initiatives such as the smart grid and smart substation

Conclusion

Data management is a critical ingredient in creating the intelligent grid. The Operational Data Manager is also an important component to maximizing the benefit of AMI systems by providing timely reconciliation of AMI data with all critical operational data sources and making it actionable to multiple audiences internal and external to the utility.

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The Decentralised Control of Electricity Networks- Intelligent and Self-Healing Systems

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Keywords: agents, distributed energy, demand management

Abstract

This paper reviews the state of the art in distributed energy control systems- decentralised control techniques that coordinate the actions of devices such as electricity loads or generators. The paper reviews two recently proposed control techniques that bring significant advantages over the first-generation distributed energy or demand management systems currently being trialled. It introduces the basic operating principles of these systems, and reviews the challenges involved in realising these techniques in practical applications.

1. INTRODUCTION

There is a growing interest around the world in the benefits available from more involved control of the demand side of electricity networks. Essentially, by coordinating the responses of the many small generators or loads operating in the electricity network, system-wide gains can be realised. For business operators, the benefits here can include better network utilisation, more accurate control of loads, and improved response to system outages. These benefits, and the related costs, are now being explored by many companies in deployments around the world, mostly in so-called *demand management* trials, targeted at improving the control of loads and small-scale generation in the network.

Typically, these first-generation demand management deployments can be characterised by the method through which they elicit a response from the demand side resource- the load or small generator under control. Most techniques rely on one or both of the following mechanisms:

- Getting a person to change the operating state of a load or generator in response to a time-varying price- so for example, the customer may disable a load when the price is expensive, but enable it at lower prices. Such techniques can scale to very large systems- the network company generally only needs to communicate a price to the network. Yet these systems are limited by the reliability, or *firmness* of response they can offer the network company.
- The network company directly controls the operating state of a load or generator via a dedicated communications and control system. These systems can offer relatively high levels of firmness, yet can be difficult to scale, as the technical challenges of controlling many thousands of devices are not insignificant.

Recognising the limitations of these first generation techniques, there are now a number of research organisations working on more advanced demand side control systems. Such systems are intended to bring a variety of benefits, including consideration of local user preferences, scalability whilst also offering known firmness, and minimal requirements for expensive infrastructure. Whilst immediately applicable to demand management projects, such systems are also being considered as a way for local users to deal with network outage situations, for operating remote area power supplies, and for coordinating localised generation and control in a way that brings benefit to surrounding users. Such benefits, and the control systems they are based on, are the subject of this paper. We will review a variety of state of the art demand side control systems, discussing their benefits and challenges, including the steps necessary before these systems are ready for commercial scale deployments.

2. IMPROVED CONTROL OF LOADS AND GENERATORS

Before describing the most recent techniques being considered for the control of loads and generators in the electricity network, it is worthwhile first reviewing what the characteristics of an optimal control system are.

As introduced above, one of the first measures of success for a control system managing large numbers of small loads and generators is its scalability- how well a given technique can cope when the number of devices under control increases arbitrarily. Importantly, in parallel with any consideration of the system's scalability must be an awareness of the system's depth of control- whilst a simple broadcast based control system may be highly scalable, such shallow consideration of the implications of control will significantly limit uptake of such a simple system. For example, consider a simple demand management system that broadcasts a "turn off" command to thousands of air-conditioners. Without consideration of the operating parameters of those air-conditioners- for example, whether a homeowner is comfortable, there is likely to be a public backlash against this system. Additionally, without an awareness of how many air-conditioners were actually *on*, it is difficult to obtain any degree of firmness of response from such a system. Thus, not only is scalability important, but the control technique must have a reasonable depth of control- it should consider local device constraints such as temperature boundaries for loads such as air-conditioning or refrigeration, fuel costs for generators, and so on.

Whilst, as introduced earlier, a firmness of response is necessary in a well performing control system, this firmness should continue through changing system conditions- so the control system should be dynamic and responsive. Additionally, the optimal control system should be robust against attack or failure- there should be no single point whose failure will jeopardise the operation of the entire system.

Given these desires- a system that provides firmness, yet considers local user constraints, is scalable and can respond dynamically to network conditions, many researchers are trending away from the more traditional control techniques used in electricity systems. Such centralised control systems, where a large central controlling entity makes decisions and communicates these to the wider network, are increasingly being pushed to their limits [1]. The growing complexity of control needed, particularly when faced with the large, diverse range of devices operating at the demand side of the network, means that centralised control systems are facing significant challenges of reliability and scalability [1], [2]. Given these limitations, the research community is trending towards a decentralised approach to the control of electricity networks. Such techniques often employ agent-based technology, where the overall behaviour of the system emerges from the behaviour of individual *agents*- individual smart devices that manage particular network components, and communicate with each other to achieve given global goals.

In work such as [2], [3], these decentralised agent-based techniques are considered for the control of relatively large network assets, with a focus on applications such as network protection, system operation and restoration after outage. In this paper, we are more interested in the use of decentralised control techniques for managing loads and generators in the demand side of the system- initially for application in demand management programmes, but later as a way of intelligently managing low-level network behaviour. An example deployment of a system of agents being used to manage the consumption and generation of electricity in a residential situation is shown in figure 1.

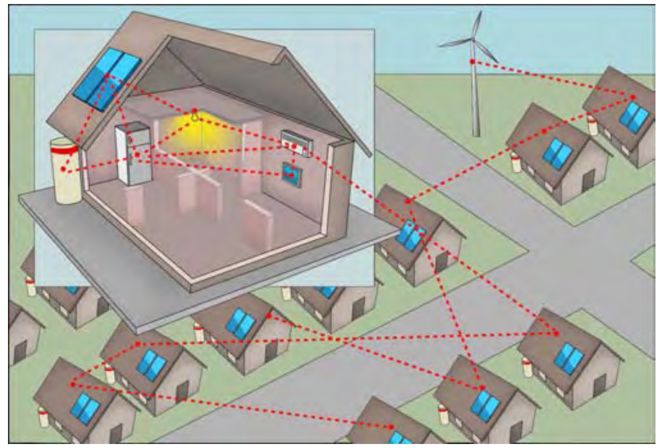

Figure 1. Agents used for controlling various loads and micro-generators in a residential setting

This is a relatively new application of this technology, and is quite different in approach to the first generation techniques currently operating in the demand side of electricity systems. In the following sections we review some of the most significant work in this area.

3. CONSUMERS AND SUPPLIERS- MARKET TYPE CONTROL SYSTEMS

One of the fundamental challenges when wanting to design a sophisticated, flexible control system is meeting the often conflicting requests of individual components of the system, whilst trying to steer the system to a common goal. As mentioned in the previous section, whilst centralised control systems may be able to find solutions to a given problem using powerful computational analysis, the complexity of modern electricity scenarios means that communications and computational overheads become a significant problem.

Decentralised agent based techniques are an ideal way to address this- they attempt to push much of the local computational load back on to the local agents, meaning local constraints can continue to be considered, whilst system goals are still achieved. To resolve the often conflicting requirements of multiple agents, one of the most common techniques used is to construct a "market", where a currency is introduced to the system, and local agents will negotiate with a broker to determine the cost of their desired action.

Running a successful market based system for controlling demand side energy devices is a challenging and novel concept, and thus there has recently been a significant amount of research dedicated to this area. Whilst limited to simulations, Ygge's work in [4] introduced the concept of a market for managing generation supply and demand. Further theoretical analysis considered features of both economics (for the market) as well as control theory, to prove the validity of this basic approach [5], [6]. Most recently, this work has resulted in an algorithm that has been trialled in practical deployment- the Powermatcher algorithm. As described in [7], the main goal of Powermatcher is to match the supply available from many small electricity generators operating in a minigrid, with a variety of small loads operating in the same minigrid.

In the market-based control paradigm, each load or generator is considered as a resource agent (RA), and there exists a broker agent (the "SD Matcher") whose aim is to fairly distribute the limited generation resources amongst the consumers. Resource agents issue bids to the broker agent, consisting of a proposed demand or supply at a given price. The broker evaluates all the bids, and adjusts the resource price in an attempt to make the total requested demand equal to the available supply. Thus, price becomes a signal of the relative scarcity of generation capacity at any given time- agents will continuously revise their bid, ensuring that the total amount of resource requested or offered (and thus its cost), matches the value (benefit) they will gain from the resource.

Particular resource agents will always strive to optimise the economics of their operation (minimise cost for loads, maximise revenue for generators), but are constrained by local parameters such as temperature boundaries, fuel supply, etc. Thus, the local constraints of an agent are implicitly recognised in the market process- for example, in a refrigerator agent if turning off the load will cost too much due to goods spoilage, then the agent will bid a high price so it can consume electricity. This selfish behaviour of local agents causes, over time, electricity consumption to be moved into periods of low price, and electricity generation to be moved into periods of high price. As a result, a match between supply and demand gradually emerges at the global system level.

To deal with very large systems of loads and generators, Powermatcher uses a tree structure of brokers to group market functions, as shown in figure 2. Here, a relatively small group of agents communicates with one particular broker, and the functionality of these brokers is aggregated upwards. The broker at the root of the tree (who is not aware of whether the agents below it are other brokers, or actual resource agents) forms a price for the entire network, and this price then propagates through the other brokers down to the bottom of the tree.

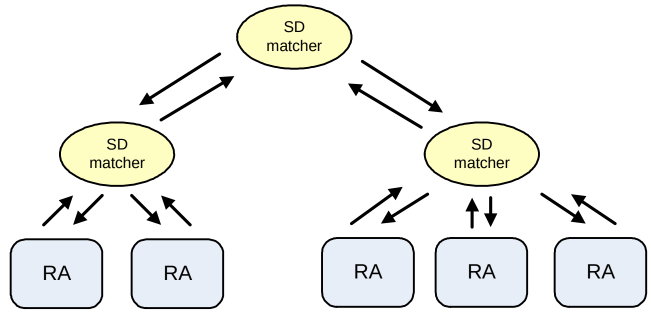

Figure 2. The hierarchy of the market-based coordination technique

Powermatcher has been tested in a variety of deployments. In one deployment Powermatcher was used to coordinate the power outputs of loads such as cool stores and residential properties, with a variety of distributed generation including residential combined heat and power (CHP) plant, diesel generator sets and wind farms. The aim of the coordination was to attempt to level the output of the combined set of loads and generators, relative to a situation where there was no coordination of the devices [8]. In another trial, the Powermatcher system was used to reduce the peak load on a residential sub-station by coordinating the output of many micro (1kW) CHP plant [9].

4. CAP BASED COORDINATION

In contrast to the market based work described in the previous section, CSIRO has been exploring an even less centralised way of coordinating the behaviour of a variety of agents controlling distributed energy resources.

CSIRO's coordination algorithm is based around four entities- a collective of resource agents, one or more brokers, an information repository (or "bulletin board"), and a summing agent. In the system, resource agents plan their local electricity demand for some period into the future, and then place these plans (which consist of simple statements of power consumption per interval of time) in to the information repository. The plans for all the agents are summed by the summing agent, to get the total predicted power demand for a particular time interval. This sum is then made available to the resource agents, as well as a demand cap figure, which indicates a desired *total* power consumption, for all agents, in the given time interval. The power cap is set by the broker agent, based on information such as prices from electricity market brokers, or status information from network operators.

Once a resource agent has observed the total power and cap figures, it will then try and modify its planned power consumption, to minimise consumption during intervals where total planned consumption is greater than the cap. In modifying its power consumption, a resource agent will

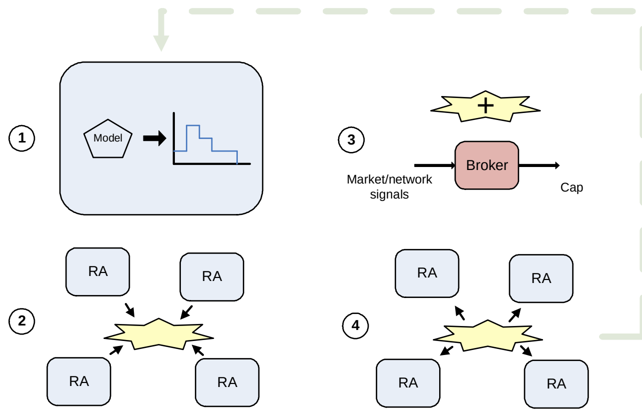

Figure 3. Operation of the cap based coordination method, including steps for resource agent (RA) future planning (1), submission of plans to the information repository (2), sum and cap setting (3), and retrieval of these from the information repository (4).

attempt to shuffle its power consumption into adjacent time intervals, creating a new planned power consumption profile. In forming this profile, resource agents will always respect their local constraints (such as temperature boundaries)- a resource agent will continue to consume energy in an interval that has excessive total power consumption, if it needs to due to local constraints.

Resource agents submit the revised power consumption plan to the information repository, these are summed, a new total power sum made available, and so on. This process continues to iterate until the cap is met, or the number of system iterations exceeds a predetermined threshold, indicating the cap simply cannot be met for the given interval. It is important to note that the entire process here is asynchronous- no explicit coordination is needed between plan submission, summing and cap setting.

The various steps involved in the cap coordination control technique are shown in figure 3.

This cap based coordination approach has been tested in both simulation and practice, controlling real electricity loads such as refrigerators. We have analysed a variety of features, such as how long the system takes to converge to satisfactory consumption plans for different power reduction goals, or the amount of warning agents need before a cap will occur, in order to be able to shuffle their power consumption around to meet the given cap.

5. INTEROPERABILITY & IMPLEMENTATION ISSUES

The previous two sections discussed the state of the art in control systems for realising a common outcome from a group of distributed network resources. Both the techniques discussed have been implemented in real-world trials, and it is worthwhile discussing some of the common interoperability and implementation issues encountered in these trials.

5.1. Intelligent local devices- the ability to model and plan

One of the key components needed for operation of both the market and cap based coordination techniques is for local resource agents (say, loads or generators) to be able to model and plan their behaviour. In a market based scheme such a model is needed to evaluate the cost one is prepared to accept for a given action, whilst in the cap scheme a model is needed so the agent can submit a plan of its future consumption. Given the dynamics involved, formation of such a model may not be a trivial process. For example, consider the situation of a resource agent being associated with a large cool room. Refrigeration plant such as cool rooms makes up a very significant percentage of Australia's electricity load, and is thus an ideal candidate for dynamic control. Most importantly, cool rooms have significant thermal mass, meaning that they are essentially a discretionary load- they can be turned off for a period of time, with little effect on the operation of the cool room, but potentially great benefit during times of network constraint. To participate in a market or cap based coordination technique as described in this paper, the resource agent controlling a cool room will need to plan operation of the cool room for some time in to the future. To do this, the resource agent will need a model of the cool room, so it can determine when the refrigeration plant will need to run in order to maintain the cool room's temperature within given boundaries. Such a model must be dynamic- it should cope with different stocking conditions of the cool room, and will need to consider ambient weather conditions, heat loads and so on. We use so-called *machine learning* techniques to learn this model of the cool room, which are essentially a "black box" learning technique- we are able to form a model of the cool room's behaviour with minimal understanding of the internal operation, or first-principles characteristics of refrigeration plant. More specifically, we use a support vector machine (SVM) based learning method, a technique which has been of significant interest in recent research publications- see for example [10].

Basically, the SVM model "watches" the cool room's behaviour during normal operation, collecting several heating/cooling cycles worth of temperature and refrigeration plant (on/off) data. This data is used to train a learning model of the cool room, which essentially finds a characteristic system temperature curve. This model can then be time-stepped into the future, providing accurate temperature predictions of the system.

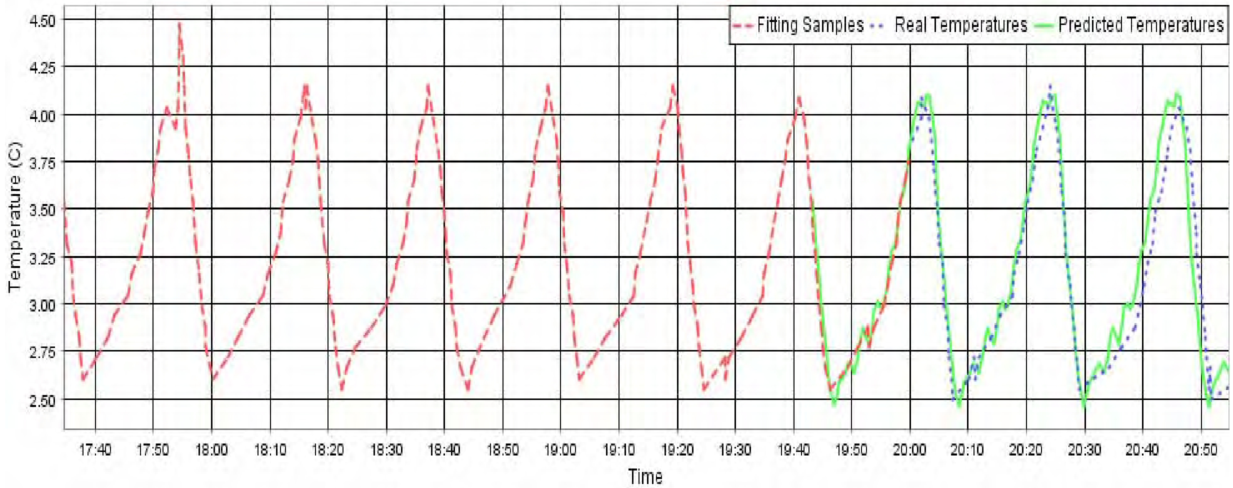

Figure 4: Operation of the machine learning technique for determining a thermal model of a cool room

This learning behaviour can be seen in figure 4, which shows the training samples, the predicted and actual temperatures for a period of cool room operation. It is interesting to observe the behaviour of the system at time 17.54, when the cool room door being opened causes a spike in the internal temperature. The learning model was able to identify this sample as having a minor effect, and so the contribution of this training data to the predictive model is minimal. This is a key advantage of SVMs- their ability to intelligently filter outlying data points, and model non-obvious system subtleties like overshoot and leakage which affect the fitting samples.

The types of models discussed in the preceding paragraphs are critical to the operation of an intelligent and dynamically reactive electricity control system. As another example, consider a renewable energy generator such as a wind or solar plant- for such a generator to participate in coordination systems such as those introduced in this paper, it will need to determine the electrical power it can contribute some time in the future. This is a challenging task for renewable energy systems with intermittent sun or wind availability, and CSIRO has spent a significant amount of time working on machine learning techniques that can autonomously form models of dynamic systems such as renewable generators or thermal loads. Details of these techniques can be found in [11].

5.2. Implementation Challenges

A key feature of the learning and modelling techniques described in the previous section is the need for a reasonable computational ability at each resource agent, so the agent can run these modelling algorithms. Our experience is that a variety of economical and reliable controllers are now available for associating with plant such as generators or cool rooms. We have experimented with a variety of computing platforms for running these models, from thin-client based devices, to personal digital assistant (PDA) type platforms.

Another challenge to the implementation of distributed systems such as discussed in this paper is the need for a communications network to link the various agents in the system. At face value such a requirement does not seem particularly arduous- reasonably reliable, high throughput communication networks are almost ubiquitous now. However, the practical implementation of such systems has proven challenging- we have encountered issues such as:

- Maintaining connectivity through different corporate firewall systems
- Given the plethora of communication platforms currently available, it is difficult for utilities to invest in a given technology with any confidence, particularly considering the long (10 year plus) investment cycles typical to electricity networks
- Ensuring the multi-agent system performs reliably and intuitively when faced with the brief but common communications outages typical to modern Internet protocol (IP) based communications systems

These challenges are gradually being mitigated by recent standardisation activities focussed on introducing reliable, ubiquitous and economical communication systems targeted at electricity network operation and control. For example, the recent IEC61850 standard is aimed at applying common IP based communications techniques to the control of electricity network infrastructure, but with the necessary reliability and robustness built in [12]. Another relevant standard to our work is the Standards Australia standard AS4755, targeted at creating a standardised communications system for the control of distributed energy devices [13]. In the scenarios envisaged by the IEC61850 and AS4755 activities, the resource agents as discussed in this paper might reside on a smart meter appliance, or home "gateway" product, thus addressing the communications and computation functionality requirements discussed above.

6. CONCLUSION

First-generation demand-side control systems are being rolled out in electricity networks across the world as a way of improving network reliability, managing operating cost and infrastructure investment. Whilst it is certainly encouraging to see these systems and the benefits they bring, such systems have a number of drawbacks related to flexibility, consideration of local user constraints, and available firmness.

This paper introduces two new techniques being studied by researchers for more optimal control of demand side resources such as electricity loads and distributed generation plant. These techniques are based around the decentralised control of such plant- there is no centralised hierarchical control system managing individual system devices. Rather, individual devices are controlled by agents, and a system of agents negotiates amongst themselves on how to achieve a desired outcome, with known firmness, and whilst considering local constraints.

The market and cap based coordination mechanisms introduced in this paper have both been trialled in real-world situations, with encouraging results. Importantly, such systems require relatively advanced computational ability at a local load or generator for forming predictive models of that resource's behaviour, and communication networks that can facilitate the inter-agent negotiations necessary to meet a system request. Recent standardisation work, and the ongoing growth of cheap, ubiquitous computing and communications networks means that these are not particularly difficult requirements; we thus look forward to growth in the uptake of these intelligent control systems in years to come.

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Biography

Having completed a PhD in telecommunications and worked for a variety of companies from engineering consultancies to Nokia Mobile Phones, Glenn now works as a project leader for CSIRO's Division of Energy Technology. There, he runs a research programme focussing on applying innovative information and communications technology to improving the way we distribute and utilise energy.

How will interoperability between systems, IEDs and functions enhance the utility business?

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Keywords: Interoperability, utility, business, information.

Abstract

While most utilities recognize the possible advantages of interoperability and networking applications still many of the applications used today are run in so called information silos, where each application has its own dedicated communication path and/or protocol. Due to the deregulation of the power industry utilities are now forced to operate much closer to the operating limits of their high voltage network and this has led to a search for solutions that allow responses in a much more dynamic way.

New solutions are preferably integrated into a single networked architecture supporting new functionality such as dynamic access to all kinds of information. Networking however does not come for free. Utilities will have to invest in the infrastructure because of bandwidth, performance, stability, access and above all information security.

1. INTRODUCTION

By controlling the high voltage network more dynamically and closer to its operational limits utilities try to operate their high voltage system based on business drivers. The key to enabling such mode of operation is timely access to strategic information which needs to be derived from the data that is available at the high voltage process. This means gaining access to the raw data, turning it into information and making it available to the end-users is the key for a more dynamic operation of the power system..

But how do we make all this information available throughout the utility? After gaining access to the raw data by installing specific systems, the big challenge is to create information out of the raw process data and make that information available at the location where it is required at the moment it is needed.

An answer to this challenge may be presented by an approach that we use every day, the search engine on the Internet. The proposed solution therefore encompasses a system that would allow any employee to search for information that provides the answers to any question. This search engine like capability would allow the utility to operate in a much more dynamic and situation driven way.

When enabling all information to be accessed from anywhere many issues however arise, which need to be addressed. Examples of questions to answer include what about information security, how does one guarantee the required data stability, performance and access?

2. THE CURRENT SITUATION

In modern days utilities there are solutions in place for the supervision, control, and data acquisition of the power system. These so called SCADA systems have been defined, installed and are operating now for many years. Recently, through the deregulation of the power industry, utilities have been facing new challenges for the operation of their high voltage infrastructure. Based on market forces, the utilities are now forced to operate much closer to the operating limits of the high voltage network in order to be more cost effective but also to support all the transmission of power though its network based on trading agreements made on new emerging energy markets.

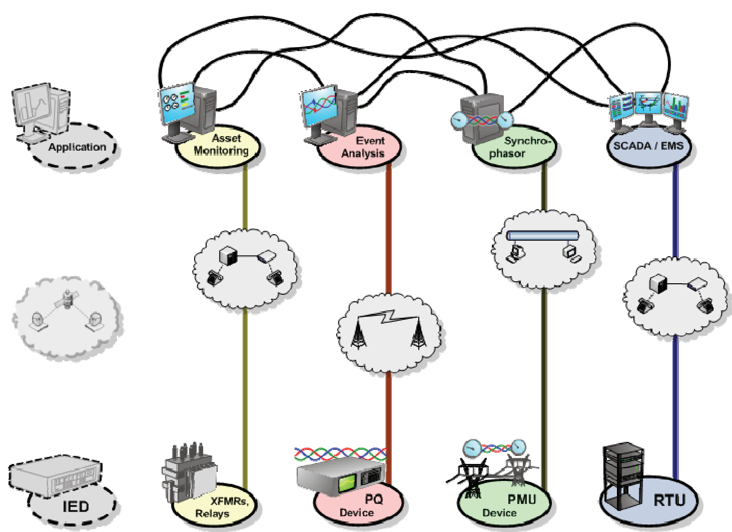

Fig. 1 Examples of information silos

This has led to a need for utilities to keep a closer watch on their assets. At first new monitoring systems were installed each using their own proprietary way for communication with the enterprise level.

Recently utilities have started to consider the integration of monitoring systems in a new philosophy in which the so called "information silos", as shown in figure 1, are integrated into a single solution that collects, manages, stores, transmits, calculates and transforms data as shown in figure 2.

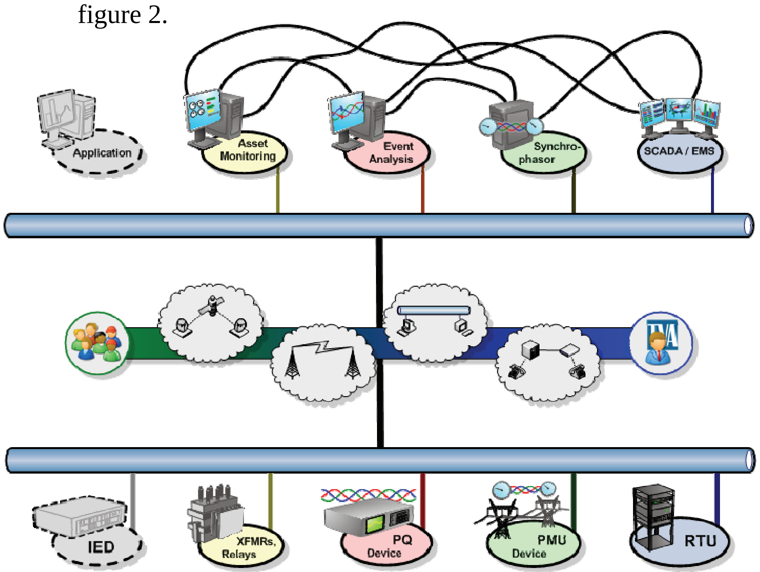

Fig. 2 Integrated substation automation strategy

This new generation substation automation systems is enabled by recent developments in the utility industry towards the interoperability of products and solutions.

The development of international standards, such as IEC 61968 and IEC 61970 defining a Common Information Model (CIM), allowing control center systems to share one data view for the definition and exchange of information is an example of this new drive towards interoperability between systems.

The introduction of IEC 61850 for interoperable communication architectures in and between substations, hydro-electrical power plants and distributed energy resources is another example of technologies adding to the possibilities for connecting systems together, thus creating networks in which free and dynamic access to information is no longer a dream but current reality.

3. DYNAMIC ACCESS TO INFORMATION

Key to enhancing the utility business lies in timely access to any kind of information available on the utility network from anywhere in the utility.

Today when a person is looking for information in the public domain, the search engine is one of his favorite tools. This because it allows him to dynamically search for information he requires at that given point in time. If a network could be created that allows such a Utility Search Engine for Remote Information for Operations and management or USERINFO™ application then this would allow utility personnel to access the available information dynamically. This would allow them to respond more accurately and timely to situations that arise with the utility.

Dynamic access to information using a search engine such as USERINFO™ comprises access to different sources within the utility network in real time. This means that these sources of information have to be interoperating and shall be networked. Furthermore in order to limit transmission delays, the used network shall have sufficient communication bandwidth. This is necessary to allow an acceptable turnaround time for any request for information. Also it allows transmitting this information to different locations throughout the utility in (near) real time.

In addition the utility will have to design and implement systems that turn raw data into information. These smart applications will have to combine different sources of information and generate more, better and more efficient information to end-users.

4. EXAMPLE SCENARIO'S

Within utilities a differentiation exists between operational data, maintenance data and management data, especially where operational data is used by the SCADA EMS or DMS system to control the high voltage network in real time. Maintenance and management data can be used for the support of the utility operations as well as the business models.

4.1. Dynamic Asset Management

When new equipment is installed the equipment details shall be entered in the asset management database. If the equipment is not networked this information in many cases shall be entered manually which can be a laborious process. When the equipment is networked however the information regarding the equipment can be retrieved automatically at the moment the equipment initializes for the first time. This avoids not only the manual entry but also assures the correctness of the data in the database thus avoiding database pollution because of wrongful entries.

Furthermore if at any given time someone within the utility needs information regarding the status of any given asset this can be acquired dynamically within a very short period of time. This does however require that all relevant asset information is accessible online.

The capability to dynamically assess details about all networked assets allows for new and more efficient methods and applications for asset management to be installed.

4.2. Accessing Power Quality information

Another application that is facilitated by networking equipment is the access to Power Quality information. More and more utilities are confronted with rules and regulations regarding the required quality of power set forth by regulators. The penalties for not fulfilling these requirements or in some cases the bonuses for performing better than required can be substantial. Therefore having the information regarding the quality of power at any given node in the network can be beneficial to several organizations within the utility.

In case of a power quality event the responsible department can assess the data recorded by the equipment quickly and perform an evaluation on the effect of the event on the overall performance indicators used by a regulator and propose scenarios to stay within the required quality thresholds.

4.3. Dynamic calculation of voltage stability and available reactive power

When building complex applications that require information to be gathered in (near) real time from multiple sources interoperability is one of the key pieces to facilitate this.

If in an area there are voltage stability problems the utility would like to have insight into not only the reasons of the instability but also the available resources within the network to counter the problem before it leads to brown outs or black-outs.

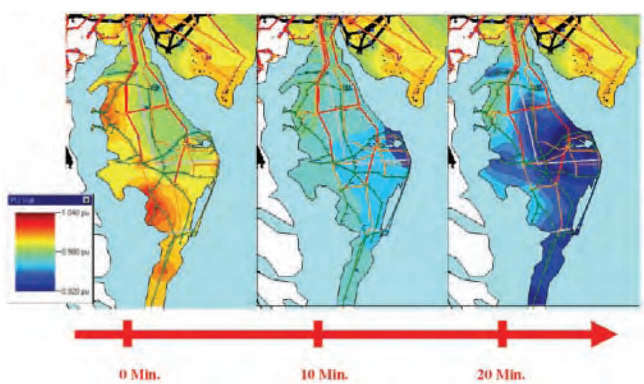

Fig. 3 Example of voltage degradation over time

One possible solution may lie in using the information from networked equipment throughout the high voltage network that gather voltage and current related data continuously and feed this information into an advanced algorithm that dynamically calculates the voltage stability, the available and controllable reactive power reserves in the entire network and presents its output to an operation as an overlayed moving image in the same fashion as the weatherman on TV showing us the buildup and movement of a rainstorm. An example of such an image is given in figure 3. We see a voltage degradation in an area over a period of roughly 20 minutes. The colors indicate the severity of the degradation.

5. REQUIREMENTS AND LIMITATIONS

When enabling interoperability between systems and networking them into a single infrastructure all information can be accessed from anywhere. This leads to the question which requirements and limitations apply. For example what about required bandwidth, what about information security, stability, performance and access.

5.1. Communication Technology

In order to provide all information in (near) real time the equipment must be connected to a communication infrastructure that supports the information throughput required. At this time there is not one single communication technology that supports the networking of all kinds of equipment can be used. This means that any given architecture shall support communication of data over a multiplicity of technologies and protocols in a seamless and interoperable way. Achieving this however is a challenge since there is not one standard solution. Development of standards such as IEC 61850 and IEC 61968 and 61970 and the harmonization between them will allow for a seamless communication between substations, hydro-electric power plants, distributed energy resources (DER) and the enterprise level within a utility. Expanding the solutions into interoperating with e.g. residential systems, the home area network or the Advanced Metering arena still leaves many questions unanswered since there does not yet seems to be a dominant technology that supports all the requirements for each of these areas.

5.2. Information security

Access to all the information within a utility can cause serious security risks which is why security must be designed into the architecture so that can be managed who should have what kind of access to what kind of information. This means that any solution shall be restrictive by default. No user shall be granted any privilege except where explicitly assigned in configuration. The USERINFO™ application shall therefore provide for assignment of privilege to an individual user or designated groups of users or roles. In addition, distinction between read-only and write access as well as privileges associated with individual devices as well as groups of devices shall be supported.

There are several security standards that can be used to build a secure architecture. For North America the solution shall at least comply with NERC Standards such as:

- CIP–003–1 — Cyber Security — Security Management Controls
- CIP–005–1 — Cyber Security — Electronic Security Perimeter(s)
- CIP–007–1 — Cyber Security — Systems Security Management

relevant are however also many other standards on security such as the IEC 62351 series that describe the communication network and system security. Once the secure architecture is in place access to the various kinds of information for a wide variety of users is supported.

6. CONCLUSIONS

By creating an interoperable networked architecture the utility can support more dynamic and (near) real time access to data from multiple sources. This allows for shorter response times to questions, problems, etc. as well as the implementation of smarter applications that support a more efficient way of operating, maintaining and managing the utility business.

The infrastructure required however must be built first which will require significant investments as well as overcoming the issues of not having interoperable solutions available at all levels.

In addition the utility will have to overcome the issues of bandwidth, information security, stability, performance and access.

We are not there yet but certainly on the way of getting there and new developments should focus more and more on providing interoperable solution for the communication of information throughout the utility from customer to enterprise and back.

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Biography

Marco C. Janssen received his BS degree in Electrical Engineering from the Polytechnic in Arnhem, The Netherlands. He has worked for over 17 years in the field of Protection, Control, Monitoring, Power Quality, Advanced Metering Infrastructures and Substation Automation. From 1990-1995 he was a Technical Specialist in the Protection and Automation group at NUON, The Netherlands. In the period 1995-2001 he was a Senior Consultant at KEMA, From 2001-2005 he was a Marketing Manager at Electron Automation, The Netherlands. Since 2005 he is the president of UTInnovation a Swiss - Dutch company providing consulting services for Substation Automation, Protection, Communication, Power Quality and Advanced Metering Infrastructures

He is member of IEC TC57 WG 10, 17, 18, 19, the IEEE PES Power System Relaying Committee and CIGRE WG B5.TF92, and B5.11. He is editor of the Quality Assurance Program for the Testing Subcommittee of the UCA International Users Group, holds one patent and has authored and presented more than 20 technical papers and he is a columnist for the PAC World magazine

Smart Wireless Communications for Smart Devices

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Keywords: Smart Grid, spectrum, broadband, wireless, communications, Last Mile, Rural, 700 MHz, SCADA, AMI

ABSTRACT

In the context of the “Smart Grid”, interoperable systems are those that promote and enhance end-to-end functionality across systems and organizations interacting with the grid itself.

The author will discuss the Wireless Communication Infrastructure interoperability issues for Utility's Smart Grid deployments and also identify the key technical and business barriers. By relating interoperability benefits, principles, and the GridWise context-setting framework, the reader will better understand the technical and business drivers critical infrastructure companies such as Electric, Water and Gas Utilities and Oil and Gas Companies must consider when adopting licensed, broadband wireless solutions for their fixed and mobile; voice and data field communications.

Rural last-mile architectures, applications and devices will be discussed.

INTRODUCTION

The “Smart-Grid” opportunity

Electric, Water and Gas Utilities and Oil and Gas companies have well understood that their field network infrastructure is the “eyes” and “ears” of their operations – connecting remote devices and field professionals in an effort to reduce the cycle time to detect problems, dispatch technicians and increase the overall security, throughput and resilience of their multi-billion dollar production assets.

Over time these industries spent millions of dollars building specialized networks for each asset and application in the field. Often, communications have been built for specific applications (SCADA, substation automation, etc.). With the growth of higher data rate applications such as automatic meter reading (AMR) and video surveillance, some specialized field communication networks no longer effectively serve the needs of the emerging “Smart” energy-efficient world. Communications needs, capabilities and deployment is evolving from serving voice demand with intermittent data collection, to system requiring constant information flow with voice as a adjunct to the data requirements. The key to untangling the communication knot rests in architects’ ability to converge field communication needs to create true interoperability among people and machines.

Interoperability in the modern “smart-grid” encompasses seamless end-to-end compatibility of hardware devices and data flows from the customer application or equipment, through the distribution and transmission network, back to the ultimate power source. The rationale for interoperability is greater efficiency and decreased service interruptions through a better coordination of energy sources and uses (see Figure 1). This paper will focus on identifying and selecting “smart wireless” solutions that promote interoperability and enable the Smart-grid.

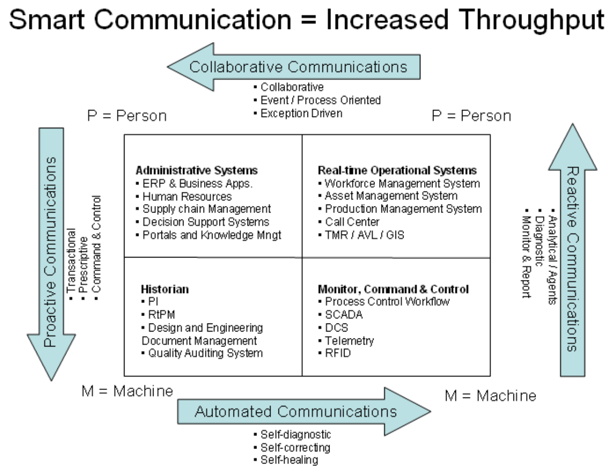


Figure 1: Benefits of smart-grid interoperability

Today, modern technology has the potential to connect the grid, increase energy savings, reduce peak power demand, and offset or avoid large generating investments. In order to achieve these benefits, the industry must shift from supply to demand response and drive exponential growth in the number of connected intelligent devices including distribution automation, substation automation, asset management, AMR, micro-grid coordination, distributed generation and appliance control beyond the meter. This technology, however, must connect the grid in a fashion that advances interoperability.

Wireless' proliferation to close the communications gap

Critical infrastructure industries still have a significant number of critical assets (substations, reclosers, C&I establishments, water lift stations, pipelines, etc.) planned for connection or left unconnected.[i] It is important to note that other critical infrastructure industries make extensive use of wireless solutions for asset connectivity. Wireless technologies by definition use spectrum which by its nature has no affinity to industry. When examining the growth in deployment the numbers are staggering.

While the electrical critical infrastructure ecosystem numbers just over 1 million assets[ii], the number expands to over 3 million when other critical infrastructure industries are considered.

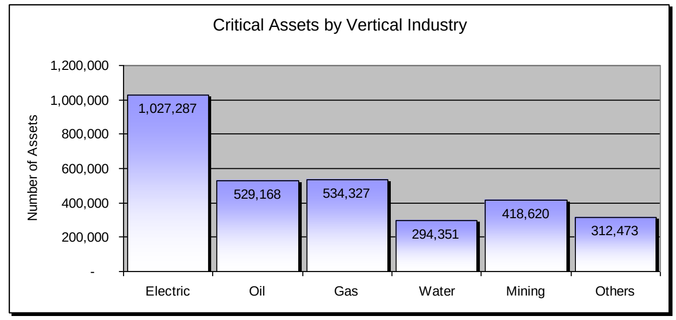


Figure 2: CII Assets by industry

These number become dwarfed by plans to deploy RF based AMI systems as outlined in the 2007 FERC report on Demand Response and Advanced Metering[iii]. The number of meters selected to be served by RF systems exceeds 19 million. When factoring in the deployments with as of yet undeclared technology choices the potential number increases to over 43 million meters (see Table 1).

GridWise helps in making the "smart" wireless choice

The demand for greater connectivity to end points creates opportunity as well as confusion for technologists charged with cost effectively and reliably engineering solutions through the enterprise and local ecosystem. In order to assist with this process, the Gridwise Architecture Council prepared a useful template for decision makers to use when reviewing interoperability of technologies being considered for use within the smart grid. In light of this framework, communications selected must be flexible to support and promote interoperability among a wide spectrum of entrenched legacy communication options, scale with the number of connections, intelligently interleave multiple traffic flows and provide data security.

Utility	AMI type	Meters	Year	Status
Kansas City Power and Light	Fixed RF	473,863.00	1996	Contracted
Puget Sound Energy	Fixed RF	1,325,000.00	1997	Contracted
Exelon (PECO)	Fixed RF	2,100,000.00	1999	Contracted
United Illuminating (CT)	Fixed RF	320,000.00	1999	Contracted
Austin Energy	Fixed RF	125,864.00	2002	Contracted
WE Energies (WI)	Fixed RF	1,000,000.00	2002	Contracted
Colorado Springs	Fixed RF	400,000.00	2005	Contracted
Chathum Kent	Fixed RF	100,000.00	2006	Contracted
City of Seattle	Fixed RF	400,000.00	2006	Contracted
Southern Company	Fixed RF	35,000.00	2006	Contracted
Arizona Public Service	Fixed RF	800,000.00	2007	Utility plans
Austin Energy	Fixed RF	230,000.00	2007	Contracted
Consumers Energy	Fixed RF	1,700,000.00	2007	Utility plans
Duke Energy in Kentucky	Fixed RF	250,000.00	2007	Utility plans
Florida Power and Light	Fixed RF	100,000.00	2007	Contracted
Hawaiian Electric Company	Fixed RF	3,000.00	2007	Contracted
Northeast Utilities	Fixed RF	1,181,880.00	2007	Filed AMI plan
Southern California Edison	Fixed RF	4,475,000.00	2007	Filed AMI plan
WE Energies (WI)	Fixed RF	100,000.00	2007	Contracted
Xcel Energy	Fixed RF	710,000.00	2007	Contracted
Anaheim Utilities	Fixed RF	110,635.00	2008	Utility plans
Pepco Holdings	Fixed RF	1,830,000.00	2008	Filed AMI plan
CenterPoint	Fixed RF and BPL	1,900,000.00	2006	Contracted
Total RF		19,670,242.00		
BGE	TBD	1,000,000.00	2007	Filed AMI plan
DTE Energy	TBD	1,300,000.00	2007	Utility plans
Tallahassee city of	TBD	107,780.00	2007	Utility plans
Utilities active in market	TBD	3,960,000.00	2007	Market Activity
American Electric Power	TBD	4,730,000.00	2008	Utility plans
Consolidated Edison	TBD	1,900,000.00	2008	Utility plans
CPS Energy	TBD	627,210.00	2008	Utility plans
Duke Energy in NC	TBD	2,200,000.00	2008	Filed AMI plan
Energy East	TBD	1,229,788.00	2008	Filed AMI plan
Florida Power and Light	TBD	3,900,000.00	2008	Pilot Ongoing
Hawaiian Electric Company	TBD	291,580.00	2008	Pilot Ongoing
Portland General	TBD	775,000.00	2008	Filed AMI plan
San Diego Gas and Electric	TBD	1,300,000.00	2008	Filed AMI plan
Central Vermont Public Service	TBD	175,000.00	2010	Utility plans
Total RF and TBD		43,166,600.00		

Table 1: Meters served or potentially served by RF systems

Communications in the smart grid can be grouped by range, quantity and capacity. For the purposes of this discussion the groupings include[iv]:

- Backhaul: MPLS/Ethernet over Fiber, Microwave, etc.
- Mid-haul: Broadband over Power Lines, 3rd Generation wireless, 4th Generation Wireless (IP Wireless, WiMAX), Licensed and Unlicensed Radio
- Last mile: 3rd/4th Generation (3G/4G), licensed spectrum carrier services, MAS radio, Zigbee / WiFi, POTS
- Home or Personal Area Network: Zigbee, Bluetooth, Serial, Ethernet, WiFi, POTS

Wireless communication options are diverse and provide a viable choice for use in the smart grid – often in the mid-haul and last mile segments.

There are a number of factors to be considered for any choice of wireless communication. The GridWise Contextual Framework provides a thorough context to review interoperability as shown in Figure 3[v]. We will use the framework to discuss the interoperability issues for wireless technologies considered for use in a utility's Smart Grid deployment and identify the key technical and business barriers to acceptance. GridWise groups interoperability into three broad categories[vi]:

- technical interoperability
- informational interoperability
- organizational interoperability

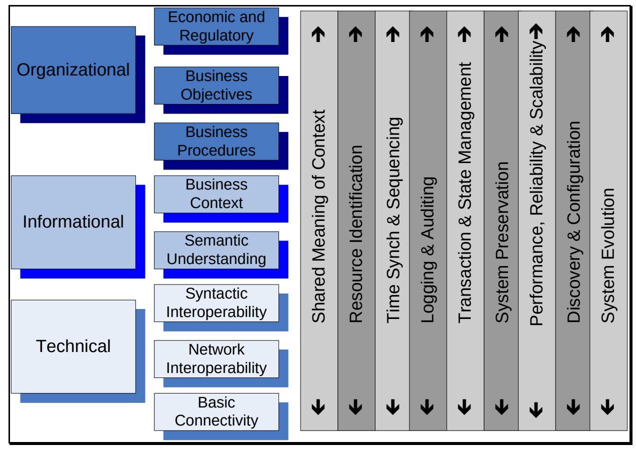


Figure 3: GridWise Interoperability Framework Design

This paper's scope will be limited to considering the interoperability aspects specifically relating to the selection of smart wireless solutions for the smart grid.

GRIDWISE FRAMEWORK: WIRELESS INTEROPERABILITY

Technical interoperability

Technical interoperability concerns the communication and physical connections between wireless infrastructure and the connected smart devices. Technically interoperable wireless infrastructure enhances end-to-end information flow.

Spectrum

Depending on the type of organization, access to licensed spectrum may involve additional cost to the overall solution. The proliferation of wireless communication deployments will necessarily increase the utilization of available spectrum potentially to the point of congestion if not properly engineered. Much of the spectrum used in the critical infrastructure space can be grouped into several holdings:

- Utility (e.g. microwave, T/LMR, MAS, etc.)

- Private/Public Carrier (Fixed Wireless, MMDS, PCS, Cellular, etc)
- Secondary Use (various)
- ISM/Unlicensed bands (900 MHz, 2.4 GHz, 5.8 GHz, etc.)

Selection of spectrum is a critical factor affecting to the level of utility, control, protection and reliability the operator enjoys on the RF link over the intended lifetime of its use.

Licensed Vs. Unlicensed:
Licensed spectrum designation identifies user priority if any for the band. Rules for each band include acceptable technologies, uses, user groups, data rate and power limitations. Licensed spectrum cost and maintenance is analogous to land rights - it is an investment asset easement in the air.

In considering such an investment, one should explore the cost benefit tradeoffs of licensed versus unlicensed spectrum. Some considerations include the economic and legal penalties associated with the networks' monitoring and reporting failure on the performance of the end device or application versus the cost of the spectrum, over the expected lifetime of the project (typically 5 years or longer). Second, consider the expected noise floor for the geography being covered by the wireless system. Organizations such as the American Petroleum Institute, the Utilities Telecom Council and the Association of American Railroads warned that if the FCC failed to take steps to transform how unlicensed (900MHz) spectrum is currently managed there would be a significant risks to the band and the hundreds of millions of devices that use it every day as interference continues to rise[vii].

Spectrum band characteristics:
Each spectrum band possesses unique physical characteristics. Several are considered below:

Selected Frequency Bands (f):

- f<30 MHz:
    - Ionospheric effects
- 30<f<300 MHz:
    - LOS space wave
    - f<10 MHz ground wave is predominant
    - Ionosphere is transparent
- 300<f<3 GHz:
    - Reflection by ground and buildings
    - Troposphere refraction
    - Diffraction over hill tops and buildings
    - Multipath effects because of trees and buildings
- 3<f<30 GHz:
    - Atmospheric absorption
    - Diffraction by precipitation

When choosing an operating band, one must match the spectrum characteristics to the desired network design. Lower operating frequencies tend to have improved long range and non line of sight (NLOS) characteristics and well as extended propagation under certain environmental conditions. Higher frequencies tend to require line of sight conditions (LOS) and exhibit signal attenuation with precipitation.

Licensing spectrum does incur a level of cost and maintenance that must be considered. It is inherently more secure than ISM bands due to reserved use by licensed operations as well as the limitation on equipment sales to licensed operators. A licensed solution gives the technologist a degree of control and predictability over the use of spectrum during the life of the deployment. Very often the licensing choice weighs the management and expectation of risk in the band against the level of assurance provided by the licensing right afforded to and mandated by the project(s) under consideration.

IP as the Interoperability standard

Due to the proliferation of wireless technologies and availability of Internet Protocol (IP) enabled devices, IP via Ethernet is quickly becoming the communication standard deeper into the grid. IP provides numerous advantages including faster polling times, flexible addressing and scalability, cyber security (encryption, RADIUS authentication, VLAN tagging, MAC filtering, etc.) and support for automatic re-routing in the event of an emergency.

IP provides a common method for networks and devices to communicate. Most legacy communications (serial, MODBUS, etc.) can be accommodated on a IP link providing a convergence advantage where more than one application can be accommodated by one IP connection – all enjoying the benefits or routing, security and often economies of scale.

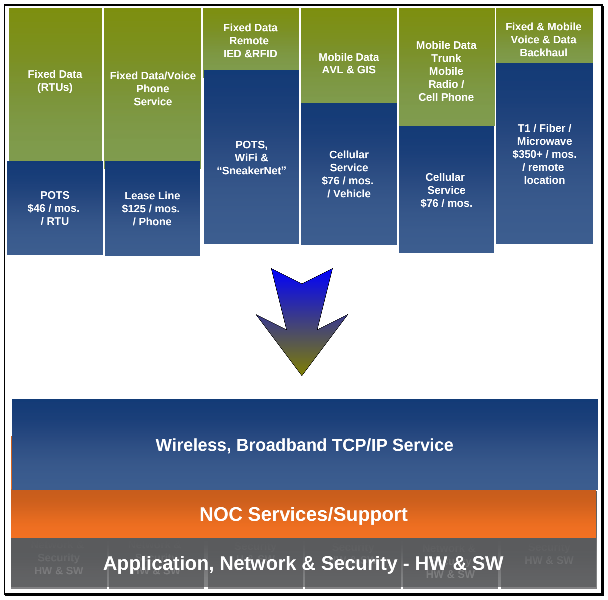


Figure 4: Convergence to integrated IP solutions

Physical connections: Power, type, path and quantity of communications interfaces (e.g. AC/DC, serial, IP)

Designed Reliability

Deployment decisions must consider the impact of the supporting infrastructure - whether it is a standalone unit or OEM device - to the expected reliability.

As a reference, consider the reliability tier definitions of the Uptime Institute which defines connection and supporting infrastructure necessary for each level of expected reliability[viii]. Factors include data distribution path redundancy, power and fault tolerance.

Tier Rquirement	Tier I	Tier II	Tier III	Tier IV
Component Redundancy	N	N+1	N+1	N+1 minimum
Distribution Paths	1	1	1 Active + 1 Alternate	2 simultaneous
Fault Tolerant	no	no	no	yes
Availability (data Center)	99.67%	99.75%	99.98%	99.99%

Table 2: Designed availability tiers

In the case of commercial wireless carriers, many have backup power; however, the available duration may be insufficient. As indicated in the independent panel review following hurricane Katrina, the FCC is only now requiring that cell sites maintain eight hours emergency backup power.[ix]

Supporting Infrastructure and Network Interoperability

When considering deployment, factors include the feasibility of supporting the infrastructure with the available power, space, and structural elements. Many backhaul and mid-haul technologies require the use of tower mounted antennas, which must be among the factors considered

Wireless communications are beneficial only if they provide communications and are available in the locations where smart devices are deployed. The FCC licenses spectrum by geographic areas or locations (e.g. major economic areas MEAs). The boundaries may or may not coincide with the utility operators’ exact area of interest.

Wireless Infrastructure Viability

Traditional utility investments have long depreciable lives usually in excess of 20 years. Smart grid applications are; however, under consideration for information technology designation with a 5-year depreciable life[x]. Under either scenario, wireless infrastructure selection must consider the vendor platform stability, commitment and roadmap to ensure long term product support and availability over the expected life of the project. For illustration purposes, consider:

- Wi-Fi was invented in 1991 and first established as a standard in 1997 with several versions A, B, G released
- 1997: GSM service launched domestically with EDGE upgrades in 2003 and migration to HSDPA begun in 2006

INFORMATIONAL INTEROPERABILITY

Smart Wireless Performance

Selection of wireless infrastructure must consider the requirements of the supported applications. Specifications include:

- Data rate capability: certain technologies (e.g. CDMA) have asymmetrical throughput from tower to remote. Selection must consider the predominant direction of traffic flow and ensure the available data rate is sufficient for applications
- Latency: when encapsulating serial data on IP technology, the added TCP/IP overhead may deliver inconsistent or excessive latency (> 100 ms range) which may be problematic for serial SCADA masters and protocols[xi]. UDP provides an alternate choice to improve consistent packet latency.
- Quality of service (QOS): QOS provides a mechanism to mark and classify data-streams,

ensuring appropriate prioritization by the routing infrastructure – especially important during periods of wireless system loading. Data priority (QOS) is rapidly becoming adopted and ubiquitous in the backhaul and mid-haul network segments. Many smart wireless communications options provide compatible QOS options capable of extending QOS capability though the wireless segment.

Network health & status

To maximize network resilience and response time as well as differentiate communications health from grid health, many utilities have telecommunications Network Monitoring Systems (NMS). While state-of-the art wireless technologies are available with element or network management packages, most are SNMP V1, V2 or V3 compliant allowing for integration with commercially available 3rd party NMS packages. Commercial wireless carriers rarely provide such network access – even in premium service arrangements.

ORGANIZATIONAL INTEROPERABILITY

Cyber security implementation considerations

Wireless communications are often mistakenly associated with Wi-Fi enabled cyber hacking. A properly engineered security plan will be largely independent of the physical connection type – wired or wireless. Adding these elements requires additional maintenance and IT knowledge from the utility. The whole area of cyber security requires a number of highly skilled IT staff in order to design, implement and maintain the entire security domain and policy. Traditionally, utilities have had two choices to modernize their field infrastructure, they could:

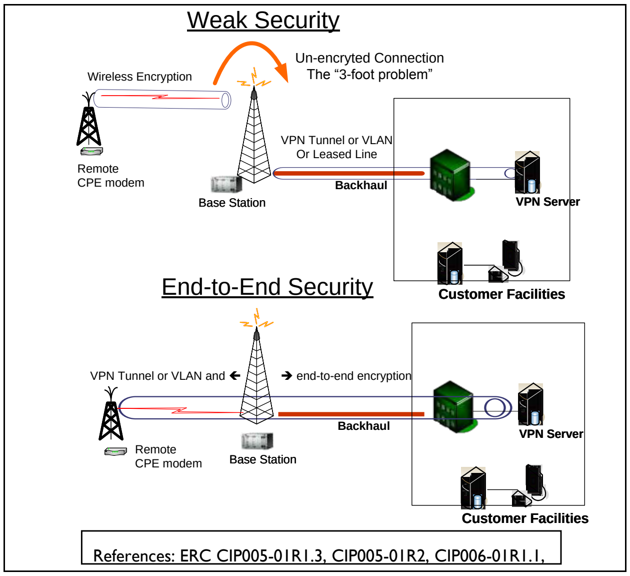
1) either build and maintain their communication infrastructure, which not only is capital intensive, but also non-core to the business of producing energy, or delivering water or gas service, or
2) partner with a consumer-oriented carriers who typically are challenged to provide last-mile and rural communication services or an SLA security and performance guarantee that meets or exceeds utility specifications.

Emerging alternatives focused on critical infrastructure, machine-to-machine and remote communications offer economies of scale associated with a consumer-oriented carrier, combined with the mission-critical security and performance requirements and flexibility of control required by today's public safety, utility and oil and gas companies. Hopefully, as the need for licensed spectrum, increased security and "smart" integrated solutions continues to grow, additional alternatives will become available to critical infrastructure companies.

Cyber security and NERC CIP ESPs

Equipment and technology are critical factors to the extent that they enable interoperability with the purchasers' security practices and NERC Critical Infrastructure Protection (CIP) standards[xii], CIP-002 to CIP-009. These CIP requirements describe proper management of secure network devices. In particular, the key concern for CIP-005, is creation of an Electronic Security Perimeter (ESP). This requires implementation of a security device at the network boundary between the substation and the external WAN environment. Currently available technologies blur the line between radio function, security function and software-based security/firewall agents present in the wireless devices themselves (encryption, IPSEC VPN, SSL, HTTPS, etc).

Careful consideration must be made when factoring cyber security in concert with physical access control at the facility. Many wireless options today provide air-link encryption compliant to NERC. It is not uncommon for multiple electrical utility entities to co-locate communications in facilities owned by one party. NERC CIP-006 requires physical security be closely managed for areas within the ESP. When CIP-005 and CIP-006 are considered in tandem however, wireless deployments using only air-link encryption may leave the link vulnerable in the facility. Firewall (VPN) functionality between the remote location and the head office minimizes cyber vulnerability at intermediate connections. Moreover, legacy systems migrated to communication links secured by VPNs, retrofits security without having to upgrade the application itself.



In order to manage compliance with intrusion detection and password management, RADIUS authentication compatibility (or equivalent) is a necessity and mandatory in selected technologies interacting at or near the ESP. Fulfillment of cyber-security needs by wireless infrastructure provides functionality capable of advancing interoperability in the smart grid while minimizing overall security risk.

Change Control and Maintenance Schedules

Selection of smart wireless options involves considering the tradeoffs of going outside the enterprise for assistance which may include risk or cost mitigation, outsourcing services, service providers, private carrier tailored solutions compatible with the smart device plans, or as a source of staff augmentation. When connecting critical infrastructure smart devices, operators should strive for maximum control over wireless network change and maintenance notification so as to minimize conflict with ISO notification, peak demand or other critical smart-grid operating periods and maximize interoperability with the System Operations requirements for the utility operator.

Financing and Ownership

Wireless communication investments require significant financial commitment. Funding profiles often differ based on the ownership structure of each utility (e.g. IOU, municipal, Coop, etc.). Infrastructure vendor selection may hinge on the financial flexibility afforded in the procurement process. Commercial carriers may sell or lease the subscriber device, whereas equipment providers often sell or finance equipment. System integrators or private carriers may have greater flexibility in offering a wide spectrum of options.

SUMMARY

This paper reviewed the interoperability issues (technical, informational, organizational) for the selection of Wireless Communication Infrastructure for Utility's Smart Grid deployments and also identified the key technical and business factors by relating aspects associated with interoperability benefits, principles, and the GridWise context-setting framework. Specifically, the paper discussed technical and business drivers critical infrastructure companies such as Electric, Water and Gas Utilities and Oil and Gas Companies must consider when adopting broadband, licensed, wireless communication networking infrastructure to converge their fixed and mobile; voice and data field communications.

ABOUT THE AUTHOR

John "Jake" Rasweiler is the Vice President of Engineering and Network Operations at Arcadian Networks, Inc. John's telecommunications career includes work at CellularOne, AT&T Wireless Services and most recently Sprint Nextel where he held positions including Senior Director RF Engineering and Market Director. His background and experience include fixed and wireless network design, site development, field and network operations, and construction. In addition, John presented at international conferences on the topics of machine-to-machine communications, the digital oil field, microcell and urban network design. He holds BA, MSEE and MBA degrees as well as two patents, is a licensed professional engineer (P.E.) and a project management professional (PMP). His current responsibilities include managing the design of custom, broadband, wireless communication services for the energy industry (electric, water, and gas utilities and oil and gas companies) using private licensed 700 MHz spectrum and converged IP platforms to improve operating efficiencies and promote future initiatives.

APPENDIX: APPLICATION OF THE GRIDWISE EVALUATION CHECKLIST FOR WIRELESS INFRASTRUCTURE ALTERNATIVES

The GridWise Architecture Council proposes a reference checklist[1] to be used by decision makers selecting smart grid component decisions targeted at advancing interoperability on the smart grid. The interoperability checklist, for the purposes of this paper, was adapted to enable initial evaluation of wireless infrastructure options and its ability advance interoperability within the smart grid.

1. Does the wireless solution specify the point of interface, whether this part of the system interacts with other elements:
   - Grid equipment
   - Software
   - The market
   - Other business organizations
   - Users/operators
2. Does the wireless solution make use of publicly known open architecture?
3. Is the Wireless solution technologically neutral?
   - Capability and performance are defined while allowing technological innovation
4. Are multiple vendor sourcing options are available to avoid being held captive by one vendor?
5. Does the wireless infrastructure rely on open and published standards for connection to network elements?
6. Does the wireless solution allow vendor and communication interface flexibility and diversity?
   - To connect with various types of communications
7. Does the wireless system use standard communication protocols capable of supporting common electric utility protocols including:
   - Modbus, DNP3, IEC 61850
   - common information models
8. Does the wireless option provide improved access and availability of data to the targeted information users including:
   - Interval data
   - Grid health
   - Operational commands
9. Does the wireless option enable efficient expansion and scalability resulting in improved efficiency and response time?
10. Does the wireless option provide cyber-security compliant with NERC CIP standards and privacy best practices?
11. In the case of mission critical electricity systems and user well-being, is adequate redundancy and protection designed into the overall wireless solution sufficient to mitigate harm to the user or system?
12. Can the wireless system software be upgraded and remotely configured?
13. Is the solution backwardly compatible to earlier generations of wireless infrastructure?
14. Do wireless options allow collaborator or users to make independent decisions through the use of authorization levels and permission?

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Utility Enterprise Information Management Strategies

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Keywords: Enterprise Information Management (EIM), Semantics, Governance, Smart Grid.

Abstract

Grid modernization is a complex issue that requires a holistic approach, chief among them is the ability for utilities core operational systems to interoperate both internally and externally in real time such that adverse events can be better managed to avoid catastrophic consequences. In an increasingly compliance-driven and competitive utility industry, information is a vital enterprise resource and is critical to business achieving success. The new responsibilities to ensure transparency, governance, quality, market compliance and information fidelity can limit bottom-line success. This paper will discuss how two utilities, Oncor Electric Delivery and San Diego Gas & Electric (SDG&E), are addressing these challenges through their Enterprise Information Management (EIM) initiatives. EIM frameworks and strategies provide a clear roadmap for utilities to establish the necessary governance and technology solutions. EIM is not only complementary to Service-Oriented Architecture, but also required for the business to drive and enable the convergence of operational technology (OT) and information technology (IT), which are key parts for the ultimate realization of a Smart Grid.

This paper shares experience of how these utilities have embarked on the journey of EIM to better prepare the enterprise business and IT for the upcoming business transformation programs such as Enterprise Application Integration, Advanced Metering Infrastructure, Smart Grid, and Asset Management.

1. DEVELOPING AN EIM FRAMEWORK

1.1. Business Drivers

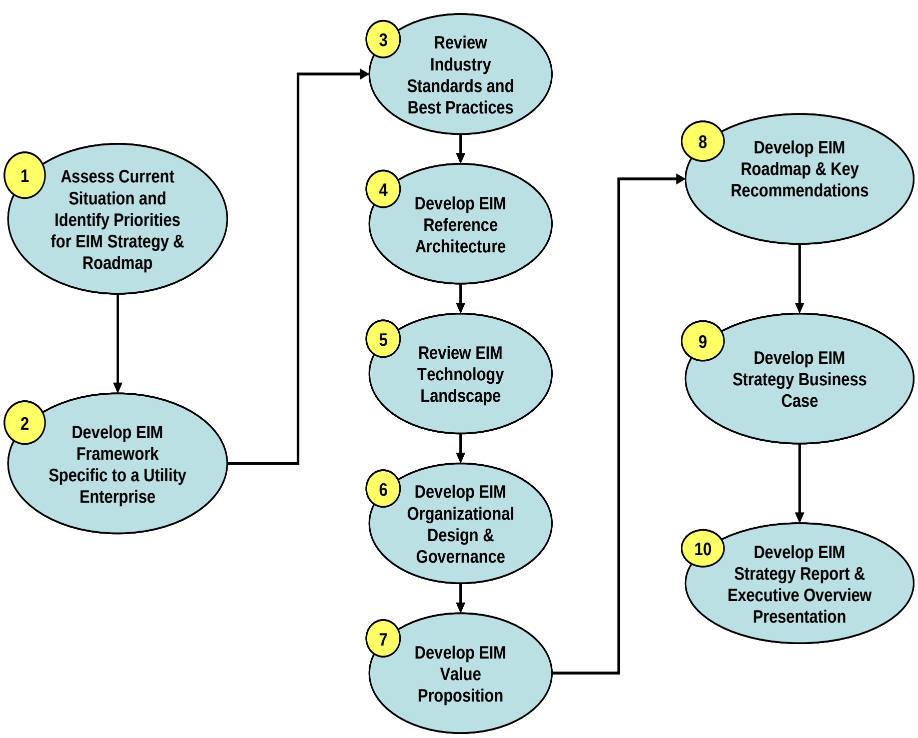
The energy and utility industry is going through a transformation as energy prices continue to rise and global warming is becoming a real concern for many. The Energy Policy Act of 2005 requires the industry to invest in technologies to deal with the increasing imbalance between demand and supply. Within utilities, we see that:

- The convergence of Operational Technology and Information Technology at utilities to enable Smart Grid and Intelligent Enterprise requires utilities to manage much more data and information and increasingly in real time;
- Operationally, utilities are also moving towards process-centric business which requires interoperability both internally and externally;
- Continued pressure to cut costs and increase revenue in an environment where both infrastructure and workforce are aging and costly to replace.

These are driving utilities to invest in technology and solutions that will enable a more agile business, and central to that investment is the ability to get more "intelligence and value" from the data that will be collected. When it comes to Smart Grid, getting the data is one thing, to be able to get "intelligent" about the data in real time requires a brand new architecture and strategy to deal with how utilities collect, use, and act upon data and information.

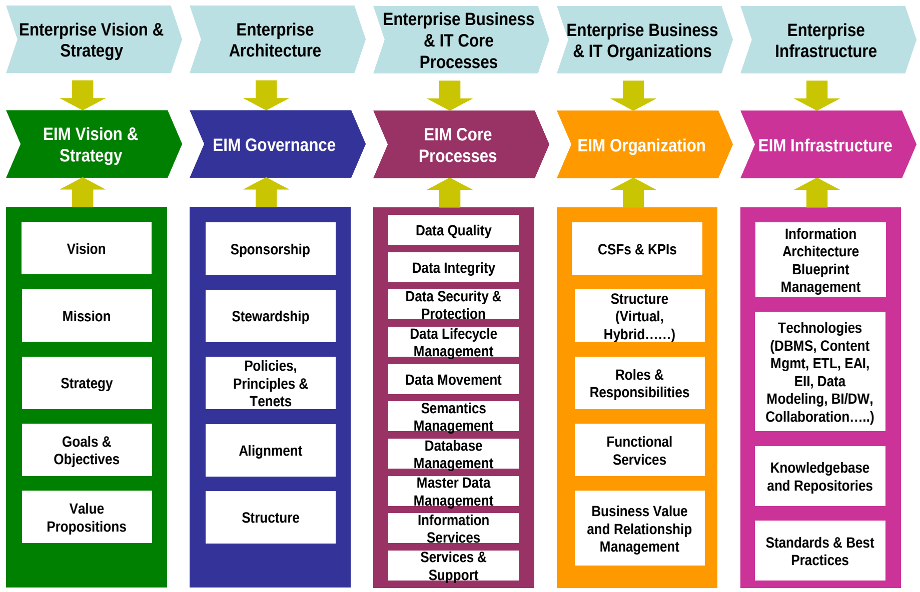
1.2. Strategy Development

To help the utility enterprise to commit to managing data and information as assets, a strategy and roadmap needs to be developed to facilitate strategic thinking amongst the key stakeholders and set paths for future pragmatic plans. The following diagram shows a ten step approach for the EIM strategy and roadmap development. A critical step of the strategy development is the definition of EIM Framework (step 4), which serves as the foundation for the prioritization and detail discussions of which parts of the Framework will be most critical to a specific utility enterprise. Finally a business case could be developed to ensure that EIM investments will bring positive and sustained benefits to both the business and to IT.



1.3. EIM Framework

As depicted in the following diagram, EIM is defined through a framework that encompasses 5 major components - vision and strategy, governance, core processes, organization, and infrastructure.



The value of the EIM Framework can only be delivered through a shared commitment of business and IT to recognize the need to manage data and information as corporate assets. The EIM Framework serves as the foundation for the subsequent discussions around EIM reference architecture, the impact of relevant industry standards to EIM, governance processes, EIM organizational models, value propositions, and EIM technology landscape. The framework prioritization process should focus around the critical needs of major business programs such as AMI, Smart Grid, etc. as well as what key recommendations we can develop to influence where and how these programs go in order to gain immediate value. The roadmap for EIM as a program could then be developed to show what the next steps of EIM could be, and where/when they would have the most impact to programs and enterprise IT activities in general.

2. EIM AT SDG&E

2.1. The Business Needs

Operational Excellence is a key mantra for many utility companies today. With this focus set utility companies are now targeting to become process-centric organization. At Sempra Energy utilities, which includes both San Diego Gas & Electric (SDG&E) and Southern California Gas (SoCalGas), OpEx 20/20's vision of 'One-hour-a-day' and 'One-work-order-a-day', will require the shift towards defining a dynamic, yet structured approach for linking and integrating various business processes spanning across the business units over heterogeneous-environment of information systems. Although optimization of complex business processes spanning numerous line of business (LOBs) offers greatest improvement opportunities, it also poses the most significant technical and organizational challenges.

Most utilities will develop business technology plans to these challenges concentrating on Process, People and Technology dimensions. However, most often these exercises fail to recognize the importance of looking at information dimension from enterprise perspective (cross-business units). (Manage information as an enterprise-wide shared strategic asset). Without this forefront view on strategic organization and management of information, the cost of implementing process-centric strategies will be prohibitive, particularly for large, complex heterogeneous environments; as information landscape will be highly fragmented and will contain significant redundancy even if we improve integration puzzle through SOA infrastructure. In addition to the desire of becoming a process-centric organization, utilities are also looking at business transformational initiatives in the areas of field workforce management, enterprise asset management, smart grid and smart metering to solve aging workforce, demand management, and reliability challenges. All these initiatives demand accurate, timely, and trustworthy data and information to drive real time decision making.

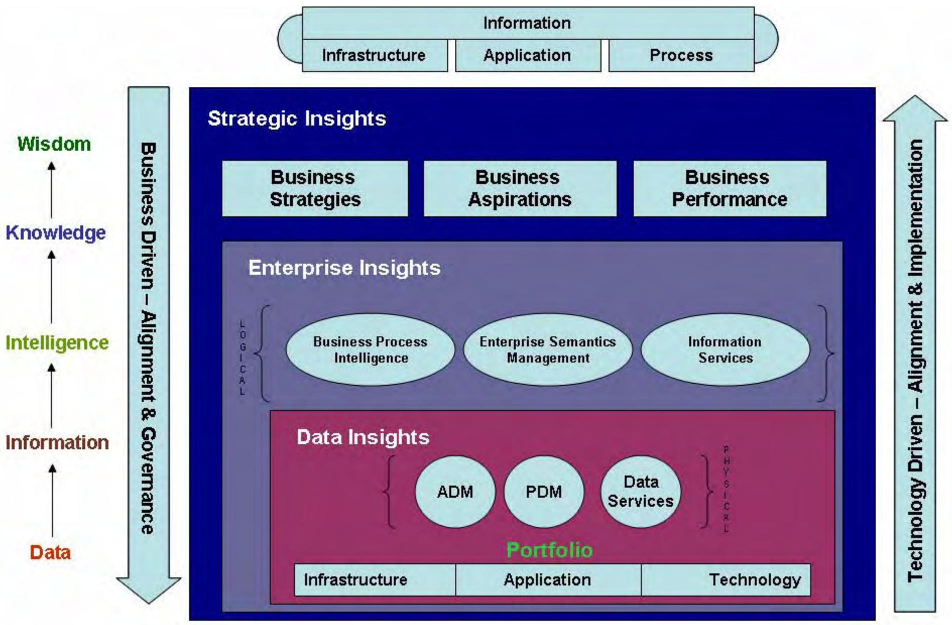
Recognizing these business drivers, SEU IT has invested in SOA integration technologies and established core competencies around them so that a solid technical foundation is put in place for more scalable, manageable, and repeatable integration across enterprise. Other initiatives such as Enterprise Architecture (EA) are also under the way in order to position IT as a business enabler rather than an inhibitor. Enterprise Information Management (EIM), as a mean to enable information architecture, fulfils a critical component of EA, and is also complementary to SOA for integration. While the current SOA investments enable systems to connect in a common way, the constructs of EIM would enable systems to talk to each other in a common business language with clarity and consistency, thus transforming data into information and business intelligence services. As the result, the combination for SOA and EIM sets up a solid foundation for business process management and services at the enterprise level, this is the eventual goal of IT.

2.2. Establishing EIM Strategy and Roadmap

SDG&E embarked on a formal EIM strategy project, where many key pieces of the EIM Framework were discussed. In summary, the EIM strategy study identified the following key points:

- EIM is a shared responsibility of business and IT, especially when it comes to data and information ownership, stewardship, governance, and lifecycle value management.
- EIM disciplines and capabilities are critical to the success of business programs such as Smart Meter and OpEX 20/20. It is well suited for the business use cases such as Enterprise Asset Management. Without EIM investment, such business programs will not be able to fully realize its benefits.
- EIM is complementary to SOA for integration, and provides a mean to leverage SOA infrastructure to establish data, information and business intelligence services across business and application domains.
- EIM is also different than SOA in that it addresses information management needs (data quality etc.) across the domains of application, integration and business intelligence, as such, should be invested accordingly.
- A critical piece of EIM is the development and management of the Enterprise Semantic Model that represents what key SEU business information entities are across enterprise, as well as methodology and technologies to drive the consistent use of the model to enable data and information services.
- Industry standards are an important reference to EIM, and have to be evaluated to ensure its applicability and value to enterprise semantic model development. The goal should be to minimize the semantic conflict among applications and processes.
- EIM organization is a formal mechanism to develop EIM related core competencies, and enable the delivery of EIM value throughout IT and business. However, the organization should be established incrementally.
- Technologies are key to the success of EIM, but should be implemented with solid business case

and fit for purpose within enterprise architecture portfolio.



2.3. EIM Value Propositions

To understand what value EIM brings to the enterprise, one must consider how raw data can be turned into information, intelligence, knowledge, and wisdom. As information systems are becoming critical to the success of business, information management must be dealt holistically.

In summary, EIM

- Enables business to take ownership, responsibility and accountability for the improvement of data quality and information accuracy and consistency.
- Enables business to establish single version of truth for data over time.
- Improves business process and operational efficiency and effectiveness.
- Provides a strategy and technique to mitigate the risks as well as maximize the value of implementing commercial packaged applications.
- Reduces the number and effort of integration over time.
- Enables the control of unnecessary data duplication and proliferation.
- Enables a more flexible and scalable process integration.
- Improves the data quality, integrity, consistency, availability, and accessibility over time.
- Maximizes the return on investment of SOA technologies.
- Establishes a critical component of the Enterprise Architecture.
- Provides guidance and services, and enables consistent implementation of SOA and information management across major programs.

2.4. SDG&E's EIM Plans

SDG&E has developed EIM strategy and business case, and is in the process of prioritizing and planning on how EIM can be best executed along with many others strategic initiatives. Such commitment shall enable SDG&E to ensure long term benefits of both business and technology investments. And as many have said, EIM is a journey and it will evolve as business and IT needs change.

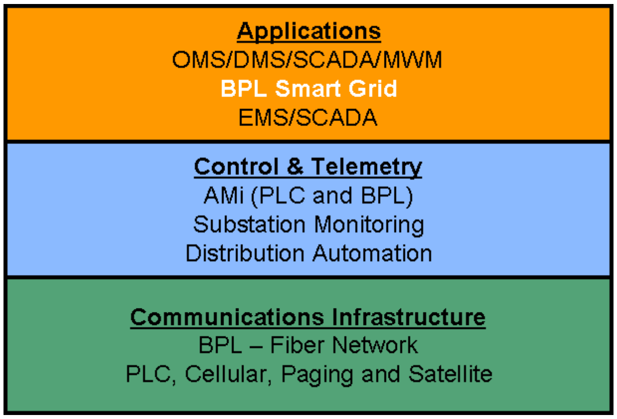
3. EIM AT ONCOR

Oncor Electric Delivery's new systems and legacy systems currently yield many sources of data with incompatible formats, making systematic organization, integration, and cleansing a big challenge. Accordingly, Information Management (IM) has established the following technology principles for true 'enterprise' integration - in which individual vendors must supply systems that function as component parts of a greater whole:

- Align Technologies to Business Objectives
- Adopt Utility Industry Technology Standards
- View Technology Investments from an Enterprise Level
- Adopt Reuse, Buy, Build Philosophy
- Treat Information as a Strategic Resource
- Promote Standardized Integration Architecture
- Select "Thin Client", Distributed Options When Available

3.1. The SmartGrid Program

SmartGrid is the first project to be planned to adhere to these principals. The essence of the SmartGrid vision is summarized in the following diagram.



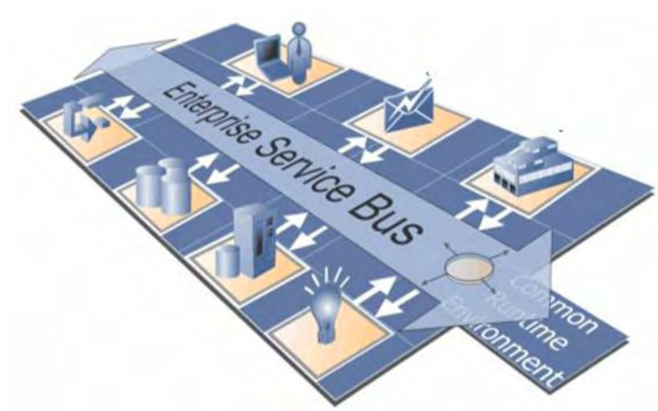
SmartGrid functionality objectives include:

- Replace an aging mobile workforce management (MWM) system that is no longer supported by vendors
- Implement a fully integrated OMS/DMS/MWM/D-SCADA system suite replacing a "legacy" home-grown Outage Management System (OMS) and several unrelated small distribution control systems
- Leverage the "new" data available through AMIS into system operations activities
- Utilize "intelligent" field mounted equipment in true "smart grid" activities
- Provide near real-time data and control to distribution operations control centers
- Improve reliability to customers while controlling costs

To accomplish these functionality objectives, the following interoperability objectives are being followed:

- Utilize "completely off the shelf" (COTS) applications wherever possible and work with vendors to update/improve applications
- Implement utility standards such as those based on the Common Information Model (CIM) to allow improved interoperability between various applications
- Leverage the "new" technologies available for enterprise application integration (EAI) by using a state-of-the-art middleware suite for new application implementations
- Utilize service oriented architecture (SOA) concepts to keep access to vital information open and easily accessed by any application
- Provide near real-time data and value-added information to all market participants in Texas (customers, retail electric providers, ERCOT, and other participants) via Web Portals and specialized information transfers

As depicted in the following diagram, SmartGrid is establishing an Enterprise Service Bus (ESB) for inter-application integration. Information exchange among services is based on the IEC 61968 series of standards, which uses the industry standard CIM for a vocabulary. Oncor is using a model driven integration (MDI) methodology to extend the CIM as necessary to plug gaps between standards message schemas and its canonical message schemas.



3.2. Business Challenges

The challenges with integrating systems are many and begin with the way systems are procured. When a project procures applications, vendors are driven by the procurement process to meet user requirements at lowest cost. Each of the procured systems has its own unique mixture of platform technologies, databases, communication systems, data formats, and application program interfaces. While Oncor prefers products that support CIM-based interfaces, an even higher priority is for product vendors to supply application interfaces that remain relatively stable across product releases. In that fashion, once an application is interfaced to Oncor's enterprise application integration infrastructure, incorporation of future product upgrades will be easier, charges for custom interface development will be decreased, and the risk of errors will be reduced during installation and maintenance of each product release. Success will depend on how well the 'how to' gaps are closed between Oncor's principles and the actual practices used to integrate applications into the enterprise. These gaps are closed as Oncor's business groups and Information Management, and all their supporting vendors, use EIM to address the key issues such as data definition; data quality; data integrity; data security; data compliance; data access and generation; data management; data integration for systems and process interoperability; data governance; and data for decision support.

3.3. Oncor's EIM Plans

Oncor has embarked on development of an EIM framework relevant to its circumstances. Establishing EIM should enable Oncor's service and application providers to all accomplish their individual functions in a manner that positively contributes to enterprise objectives. Establishment of this EIM framework is planned to be performed in steps, allowing Oncor and its providers to assess the results of each step and make course corrections before continuing on to subsequent steps. By leveraging MDI and the CIM, integration artifacts developed in the meantime should fit into the resulting EIM framework with minimal effort.

Acknowledgement

Xtensible Solutions is supporting the work described in this paper as part of the Capgemini team at both SDG&E and Oncor. Accordingly, Joe Zhou and Greg Robinson hereby state their appreciation for the opportunity to be value-adding partners in these endeavors.

Biography

Kamal Parekh:

From past 11 years in Information technology, Mr. Parekh enjoys the role of researching, developing and applying business frameworks with embedded enterprise-IT value principles. Specialization includes business performance management, knowledge management, statistical business analysis and analytical applications, which encompasses operational and multi-dimensional large enterprise-wide data warehouse architectures. Currently, as a Business Intelligence architect/strategist with San Diego Gas & Electric (SDG&E) utility, plays key role in formulating and translating EIM vision into enterprise-wide program for managing information as a strategic corporate asset. Prior to SDG&E, worked with prominent consulting organizations providing enterprise-class technology services in IT strategy and enterprise planning, systems architecture, business process management, enterprise application integration, ERP/CRM/PLM implementations, IT portfolio management and change management practices to various fortune 100 clients across vertical industries.

Joe Zhou:

Mr. Zhou is a co-founder and CTO of Xtensible Solutions, which provides enterprise information management and integration solution and services to energy and utility industry. With about 20 years of industry experience and services for more than two dozen utilities worldwide, Mr. Zhou works with his clients to build sustainable information management and integration solutions that leverage industry standards and best practices in order to enable and improve business and systems interoperability.

Kelly McNair:

Mr. McNair has led the Information Management group within Oncor's Asset Management & Engineering department for over five years. He has 26 years of extensive operations and engineering experience at Oncor, including support to Oncor's distribution operations centers, as well as holding several engineering management positions. Mr. McNair has played a central role in Oncor's ongoing transformational technology activities by overseeing the development of the current governance process and the deployment of new applications within annual technology asset investment plans. He has a BSEE from Texas Tech University and is a Professional Engineer.

Greg Robinson:

Mr. Robinson is a co-founder and President/CEO of Xtensible Solutions, which provides enterprise information management and integration solution and services to energy and utility industry. He helps utilities plan and implement semantically coherent application integration infrastructures. Mr. Robinson is convener of IEC TC57 Working Group 14, which is extending the industry standard Common Information Model (CIM) for enterprise-wide messaging. This volunteer work has enabled him to help utilities leverage and drive these industry standards to their benefit while simultaneously aiding the standards development process. He has a BSEE from Georgia Tech and a MBA from the Florida Institute of Technology.

Role of Interoperability in the Indian Power Sector

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Keywords: Interoperability, Common Information Model, Inter Control Center Communication Protocol, Indian power sector

Abstract

Economical growth in India has led to a considerable growth in its power sector. Issues related to system expansion, restructured environment, and changing regulatory framework demand changes in planning and operating strategies and in the design of system architecture for future needs. We explore the role of interoperability in the Indian power system context. Four levels of interoperability viz., organizational interoperability, application interoperability, information interoperability and technical interoperability are discussed with the help of typical scenarios. It is observed that interoperability among various systems of the power grid is crucial for achieving the benefits of open architecture based future control centers.

1. INTRODUCTION

Due to restructuring, owing to integration of multiple utilities in power systems and due to integration of power grids for power sharing, the number and the complexity of the functions that are to be performed by power control centers have increased. In order to keep up with the evolving requirements, the notion of central supervisory control is being replaced by intelligent distributed control of the system. As pointed out by Conti [1], unidirectional centrally controlled nature of existing infrastructure can be upgraded into an interactive, electronically enhanced grid that can spot potential problems in real-time, and automatically prevent or correct any faults or disturbances. Vendor dependent non-standard legacy devices with proprietary software and proprietary communication protocols are not interoperable. To achieve high level benefits by utilizing the powerful features that modern information and communication technologies provide, power systems of today need to focus on interoperability.

This paper presents the status of interoperability at various levels of Indian power organizations. First the current architecture, known as Unified Load Dispatch and Communication (ULDC) driving the power system infrastructure, at various hierarchies is described. The barriers for interoperability in the ULDC architecture due to heterogeneous infrastructure, modifications in the Inter Control Center Protocol (ICCP) standards by various vendors, and lack of common standards are highlighted. These limitations can be addressed by using a model driven approach [2]. In this case, Common Information Model (CIM) which establishes a semantic understanding among the applications, leading to common standard for information representation and exchange is employed. This paper describes how the use of CIM decreases the need of large number of adapters which are the means of application integration, thereby facilitating scalability.

As per the interoperability framework prepared by GridWise Architecture Council [3, 4], interoperability is classified into hierarchical levels. This paper identifies application interoperability as a level between organization and information interoperability levels. Application level interoperability is analogous to business context and business procedures levels of the interoperability framework by GridWise.

2. OVERVIEW OF INTEROPERABILITY ARCHITECTURE

In this section we provide an overview of various levels of interoperability, which we discuss in the paper. Figure 1 shows the interplay between various levels of interoperability. We consider organizational, application, information and technical level interoperabilities.

Organizational interoperability is ensured by a standard inter organization protocol, which expresses the way in which organizations have to communicate and share data. Likewise, within an organization that has a host of applications, application interoperability can be achieved by enforcing an inter application protocol. At a lower level information interoperability is ensured by complying with a standard information model. Finally, technical interoperability is achieved by standard device level protocols. It must be noted that interoperability of a level can be achieved independent of other levels. Hence, in a typical system, one can choose to standardize the levels in an order based on local priorities and policies. However, to realize the maximum benefit, interoperability at all levels needs to be ensured.

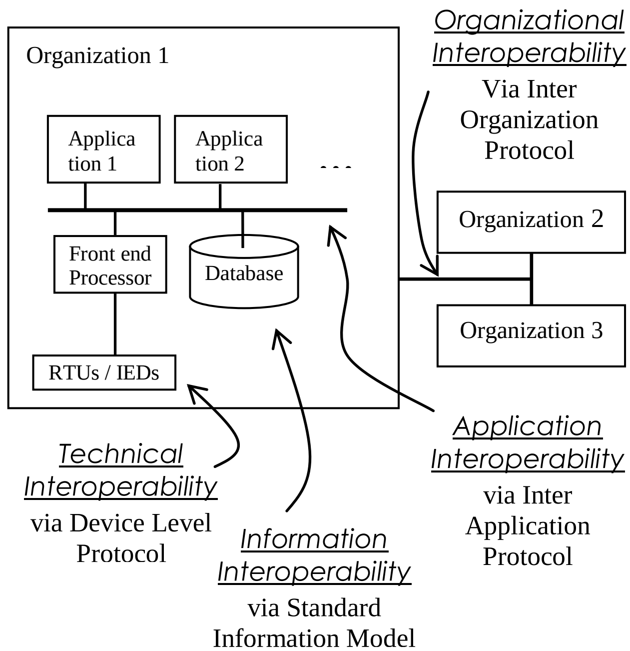

Figure 1: Interoperability Overview at different levels

3. ORGANIZATIONAL INTEROPERABILITY

Power system is characterized by vast distribution of infrastructure comprising of generation, transmission and distribution spread over a large geographical area. Though a high level centralized control center is needed for scheduling and operation of the system without interruption, certain functions can be performed by local control centers within clearly defined geographical boundaries. Thus there is a need of coordination between these control centers. However, these control centers may be heterogeneous in terms of hardware and software systems. The electricity market regulators or authorities formulate policies which define a reporting hierarchy and mandate the participating utility/organization to coordinate for operating the system. In order to facilitate coordination between control centers, interoperability is needed. This interoperability when viewed at the level of control center is studied under category of organizational interoperability.

3.1. Case study: The ULDC scheme

In India, the Unified Load despatch and Communication (ULDC) scheme is used as a structure for achieving organizational coordination. The ULDC scheme, its objectives, hardware and software architecture, and the benefits of the unified approach are defined in [5].

3.1.1. Motivation:

In India, the natural resources needed for power generation, and the load centers unequally distributed across the regions. Eastern and North-Eastern Regions are the power surplus regions and Northern Western and Sothern Region are power deficient regions. It is advantageous to shift the focus of planning the generation and the transmission system in the country from the orientation of regional self-sufficiency to the concept of optimal utilization of resources on an all India basis [6]. This resulted in need to interconnect the regional grids to facilitate inter regional exchange of power. Such interconnection mandates use of compatible software, hardware and communication protocols. But, various utilities all over the regions are using vendor specific hardware with proprietary software and protocols. Seamless data exchange between various utilities is difficult, resulting in inefficient operation of the grid.

3.1.2. Inception:

A major effort towards a unified scheme of operation and control for the Regional Load Despatch Centers and State Load Despatch Centers was made way back in early 1990's. The Unified Load Despatch and Communication (ULDC) project, also referred to as SC & C (System Coordination and Control), has been conceived to monitor, operate and control the regional power grid in a unified and coordinated manner. Monitoring of the grid system based on real-time data is vital for optimal system operation and also to minimize system tripping and blackouts. Besides, the delivery of scheduled power from Central Sector and jointly owned power plants to the beneficiary states requires a hierarchical network of load despatch centers along with adequate telecommunication facilities.

3.1.3. The operation and control hierarchy:

The control of the grid is planned to be done at three levels of hierarchy namely (1) National Load Despatch Center (NLDC) (2) Regional Load Despatch Center (RLDC) and (3) State Load Despatch Center (SLDC). Each level in the hierarchy has definite roles and responsibilities. At present, the NLDC in India is not fully operational and hence the RLDC's co-ordinate among them in the matter of inter-regional power flows. The RLDCs also have to schedule the centrally owned interstate generation stations (ISGS) and operate the inter-state grid. The scheduling and operation of state owned generation and power transmission within the state is carried out by the SLDC. The Area Load Despatch Centers (ALDCs) in turn form a lower level and are the local control centers which operate the power network of a part of a state.

The Remote Terminal Unit (RTU) is the source of information collection for the purpose of control and operation of the grid. Every RTU has a predefined Master Control Center (CC) and it has to report its data to the CC.

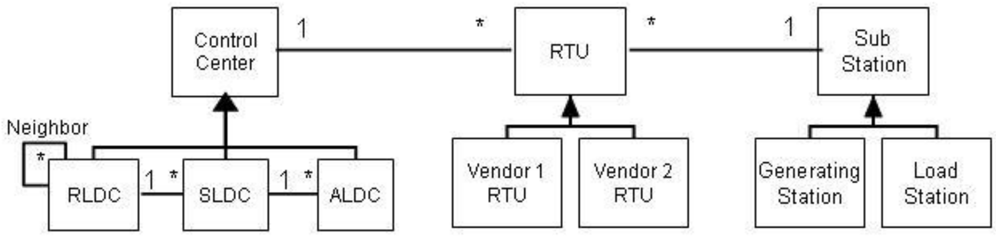

Figure 2: A model of Unified Load despatch and Communication (ULDC) Architecture in India

An RTU may be connected to an ALDC or SLDC or RLDC depending on whose data that RTU is reporting.

For example, all RTUs connected to ISGS (Inter State Generation Stations, owned by Central Government) report directly to RLDC, whereas, RTUs connected to state owned generations are connected to the corresponding SLDC. However, irrespective of the master CC, all RTUs ultimately report to the RLDC, through flow of the aggregated data between the control centers.

3.2. Scope of organizational interoperability

As a result of the ULDC scheme, a high level hierarchical organization structure is defined. This makes it easier to identify the scope of organization interoperability by considering compatibility of the equipment, standardization of hardware and software. It can be noted that information from lower level control centers to higher level control center in form of aggregation. A similar approach can be employed for exchange of control information and queries. To summarize, the information flow over the links in Figure 2 contribute to organizational interoperability.

4. APPLICATION INTEROPERABILITY

Modern control centers are equipped with a host of different applications, interacting with each other and essentially operating on the same data. Example, Most of these applications like Supervisory Control and Data Acquisition (SCADA), Energy Management System (EMS), and Business Management System (BMS) are instantiated on different servers over a Wide Area Network which may have totally different configurations and the applications themselves might be created by different vendors in different languages on different platforms. In other words, most modern power systems consist of geographically distributed assets. Even the data sources differ in terms of data semantics and granularity. It is important that in such a scenario the applications are able to communicate with each other in a standard, seamless and platform independent way.

4.1. Case study: Analytics for a large distribution utility

A distribution utility typically has a well developed SCADA system to control and operate the distribution network. However, it is observed that these operations are mainly centered on the real time data, whereas, the historical data is mainly used for basic reporting purposes.

A set of data mining applications can be developed, for extracting valuable insights about the distribution network operation from the huge database. Various other business scenarios, where such advanced business analytics applications can add value are identified as asset lifecycle management, preventive maintenance, efficient grid operation, enhanced grid observability, decision support, etc. These applications can be independently developed and provided by any third party vendors.

As shown in Figure 3, say one such application “Intelligent alarm processor” has to be deployed over an existing SCADA/EMS system. This application monitors the events occurring in the system and based on the certain events it automatically invokes corresponding services which mine the database and provide reports in real-time to support the system operator in making decisions. Such an application involves data exchange between database and other services. This creates the interoperability problems. The links in Figure 3 indentify the scope of application interoperability.

4.2. Scope of application interoperability

In order to make such a system viable the services and applications will have to agree on information exchange standards. Such an interoperability based solution will make it possible to benefit from multi-vendor implementation of services. Once application interoperability is achieved, service orientated architecture (SOA) complemented with Event Driven Architecture (EDA) can be used as an option to scale up and integrate the applications and automate the processes [7].

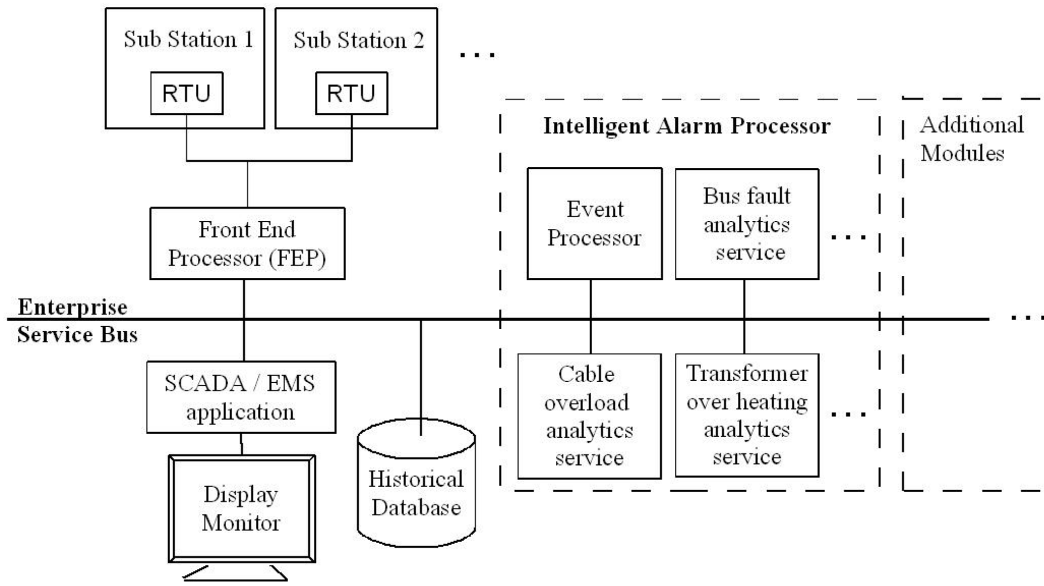

Figure 3 : Data analytics service for a large distribution utility

5. INFORMATIONAL INTEROPERABILITY

It is Interoperability by virtue of information models and protocols. The data to be processed or transferred should be stored in a well defined variable naming scheme which is known as information model. Information traveling from source over many devices to a faraway application may be mapped multiple times due to different systems, organizations, people, programming languages and communication protocols involved. This mapping creates interoperability problems. [8].

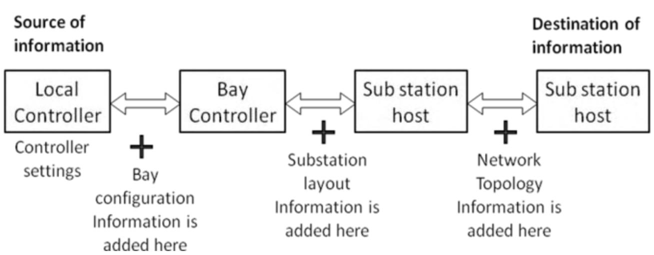

Figure 4: Multiple tagging of Information

5.1. Case study: A problem in hierarchical tagging

Consider a power system where the information from the field has to be collected and transmitted to the control center. The control center receives information from many such sources. The information collected by the source is first stored locally in the memory of the device and its address is identified a certain variable, this process is called tagging the information. Eventually when this information is passed on to other devices in the hierarchy there it will be tagged again. Moreover, this tag will also have to include the locational specification of the information to uniquely identify it as there will be multiple such data sources at this level. Thus, the information being transmitted is tagged multiple times and creates interoperability problems if the intermediate units are to be supplied by different vendors. This is depicted in Figure 4. Because of incompatible tagging schemes, one of the devices in the path cannot be replaced with that of a different vendor, although the functionality may be exactly same. This prohibits plug-and-play feature.

5.2. Case study: Interoperability between two control centers

In the practical Indian power system hierarchy the Maharashtra State Load Despatch Center (MHSLDC) falls under the domain Western Regional Load Despatch Center (WRLDC). Control centers at MH-SLDC and WRLDC have hardware and software systems from different vendors which use different information models. But their control centers have to inter operate and exchange data over the Inter Control Center Communication Protocol (ICCP) link. For making sense of the data transferred by ICCP link, we have to define the "Interoperability Table" (IOT) and Bilateral Table (BLT). IOT defines the ICCP link parameters. BLT defines the mapping of variable names between the two vendor implementations. This exercise (of defining IOT and BLT) in this case has to be performed by mutual co-operation of the two vendors, which is not easy to achieve and also a costly option for the system beneficiary.

This is typical current scenario existing in India and is depicted in Figure 5.

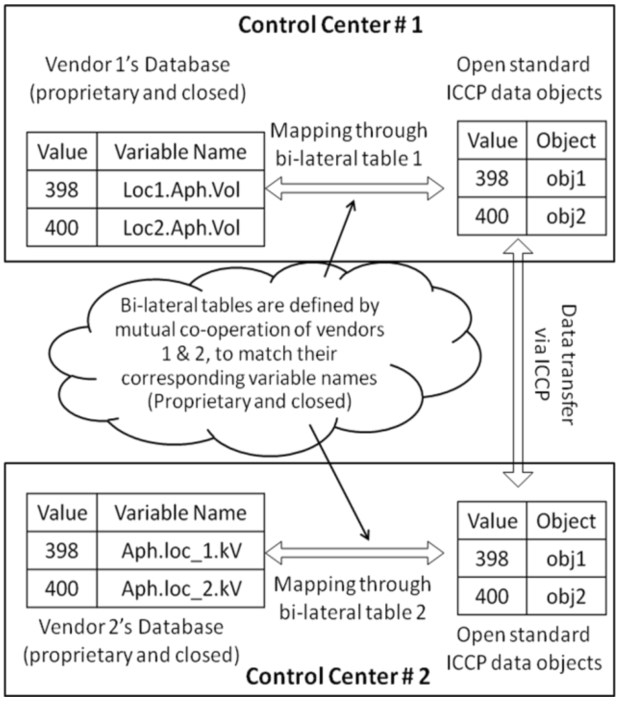

Figure 5: Typical Inter control center data transfer

5.3. Scope for information interoperability

Situations such as above can be avoided by defining a standard information model which all the vendors comply. The information interoperability can be achieved by following steps.

a) **Standardization of data types** that are needed to represent all the power system data. This can be further classified as primitive data types and aggregated data types.

b) **Standardization of naming scheme** that is needed to universally identify the variable.

The Common Information Model (CIM) is one of the means to achieve the above two standardizations. CIM is an information model, for defining data exchange semantics between the applications of various power control centers. The motivation of conceiving CIM is to achieve plug-and-play capability among the applications provided by different vendors [9]. CIM standardization exercise was initiated by EPRI over a decade ago. Today although CIM has developed as an exhaustive model, efforts are still being made to extend the CIM to account for various factors like market models etc [10]. It has become a necessity that the vendors of various SCADA/EMS software must provide CIM converters or adapters to make their proprietary information model CIM compatible and hence interoperable. In Indian context specific extensions in CIM are needed to take into account the unique local features of the power sector.

6. TECHNICAL INTEROPERABILITY

It is the interoperability at the level of network connectivity. This includes the physical medium of connection for data transfer, method to transfer data between various devices and networks establishing a syntactic understanding of the data. Usually this connectivity is achieved by dedicated hard wired communication networks, which operate with a standard protocol to drive the data transfer. However, it is envisioned that in future a more interoperable and reliable mode of network connectivity would be to use IP enabled Intelligent Electronic Device (IEDs) which have unique identification and hence can use a public network (World Wide Web) for connectivity [11]. This results in elimination of hard wired point to point connectivity and achieves universal connectivity.

In Indian power system, typically at physical level, fiber optic cables are used for inter control center communication, whereas microwave and Power Line Carrier Communication (PLCC) technologies are used for collection and transfer of data from substation RTU's to the nearest Control Center. The limitation of the micro wave and PLCC is the lower baud rate of data transfer. Above the physical medium the data transfer is achieved by the ICCP protocol [12] which is based on the 7-layer OSI communication stack. In the Indian context some efforts based on IPv6 are underway for interconnecting various networks following different proprietary SCADA protocols.

7. CONCLUSION

The role of interoperability in the Indian power system context was described with the help of a few case studies. It is pointed out that interoperability occurs at various levels. Interoperability among various systems of the power grid is crucial for achieving the benefits of standardization such as application evolution, open architecture and scalability, plug and play capability of components and services, reliability and service orientation.

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How NRECA's MultiSpeak® Specification Supports Interoperability of Diverse Electric Grid Automation Systems

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Keywords: Interoperability, MultiSpeak®, CIM, enterprise integration

Abstract

NRECA's MultiSpeak® specification is an industry-wide standard that facilitates interoperability of diverse business and automation applications used in electric distribution utilities. Interoperable MultiSpeak-enabled applications are already in place in numerous electric utilities and permit integrated operation of previously stand-alone systems. MultiSpeak provides similar capabilities to those included in the IEC 61968 distribution extensions to the Common Information Model (CIM).

This paper discusses how MultiSpeak implements key portions of the GridWise Interoperability Framework and illustrates such support by identifying examples of use cases where the most recent version of the MultiSpeak specification can already address the need for significant interoperability among systems. Such examples illustrate how the exchange of information using MultiSpeak has created the potential for utilities to perform services that were previously impossible.

The authors suggests an approach to enhancing future interoperability between MultiSpeak-enabled applications and those that support IEC 61968 CIM with the goal of achieving an integrated system using applications that support the different standards.

1. BACKGROUND

The MultiSpeak® Initiative is a collaboration of the National Rural Electric Cooperative Association (NRECA) and leading software vendors serving the small utility market. The initiative has developed and continues to refine a specification [1] that defines standardized interfaces among software applications commonly used by small electric utilities [2] [3]. Such interfaces can enable utility employees to gain a unified view of utility operations and thus improve customer service, enhance outage performance and cut operating costs.

The MultiSpeak specification defines (i) what data are typically required to be passed among software applications in utilities, (ii) the semantics of those data, (iii) a common message structure, and (iv) which messages are required to support specific business processes.

MultiSpeak defines business objects in the form of an extensible markup language (XML) schema, exchanges data in XML form, and uses web services to transport such data payloads or to invoke actions on another software system. Typically, one web service method will support a single business process step and sequences of multiple method calls will support complete utility business processes.

Additional general information about how MultiSpeak facilitates application integration can be found in a utility user's guide [4]. Additional technical information, complete XML schemas and web service method definitions in Web Services Definition Language (WSDL) format can be downloaded from the MultiSpeak Initiative web site (http://www.multispeak.org).

Taking the example of support for the exchange of metering data, MultiSpeak has a complete set of interface definitions for advanced metering infrastructure (AMI) systems and meter data management. It includes a flexible, efficient, and self-describing means to exchange large volumes of data of arbitrary content among such systems and other applications that require metering data. The authors believe that MultiSpeak can easily be extended to support the developing needs for collecting large volumes of data from in-home networks and for controlling customer equipment using an AMI system.

2. HOW MULTISPEAK SUPPORTS THE GRIDWISE INTEROPERABILITY FRAMEWORK

The GridWise Interoperability Framework [5] outlines principles that support functional interoperability. Principles can be either *categories* that are layered in application (i.e., one layer builds on the layers below, similar to the layering in the Open Systems Interconnection (OSI) seven layer reference model) or *cross-cutting issues* that need to be addressed at all layers of interoperability. The layered categories are further separated into technical, informational, and organizational aspects, as outlined in Table 1.

Category 1 is adequately addressed by existing OSI physical layer standards; Category 2 by existing protocols that are described in the network, transport and session layers. MultiSpeak makes use of common physical layer standards along with web services over TCP/IP to address transport and session services.

Table 1
GridWise Framework Categories

- Technical Aspects
  - Category 1: Basic Connectivity
  - Category 2: Network Interoperability
  - Category 3: Syntactic Interoperability
- Informational Aspects
  - Category 4: Semantic Understanding
  - Category 5: Business Context
- Organizational Aspects
  - Category 6: Business Procedures
  - Category 7: Business Objectives
  - Category 8: Economic/Regulatory Policy

Syntactic Interoperability, Category 3, concerns data formatting and encoding – typically addressed by the OSI application and presentation layer standards. MultiSpeak makes use of extensible markup language (XML) and SOAP message encoding to address Category 3 interoperability. Since these issues are adequately handled by existing standards, MultiSpeak does not address them.

Categories 6, 7, and 8 are primarily concerned with the economic and regulatory landscape. Certainly business partners must agree on services to be exchanged and regulatory agencies will establish requirements for participating in the markets, but although these issues define needs for information exchange, they are outside the scope of the technical concerns of interoperability.

MultiSpeak primarily addresses the stickier issues of common syntactic understanding (Category 4) and business context (Category 5), along with defining a consistent set of Category 1, 2 and 3 protocols to support effective messaging using web services. MultiSpeak provides for common data semantics (Category 4) by clearly defining data objects and how these objects are exchanged in support of common business process steps. The MultiSpeak object model is described in the form of a set of XML schemas. Data object definitions are adequate to support common business processes in distribution utilities. An edited set of core data schemas, called “recommended-fields” schemas, document a common understanding of which data fields are typically necessary to support utility business processes.

Objects defined in the schemas typically constitute the data payload for messages exchanged between systems. Web service methods are defined to flexibly exchange data as necessary.

Category 5, Business Context, is addressed in MultiSpeak by defining a set of abstract application functionalities. The software functions can be thought of as a framework of roles that can be served by different applications. Each abstract function has data “ownerships”, further defining the expected interaction among functions during business processes. Actual computer software can serve one, or perhaps several, of these abstract roles, thus flexibly defining the interfaces necessary to implement interoperable software in an actual utility.

Specific web service methods are defined in MultiSpeak to support a single step in a business process. Such steps can be strung together to define a complete business process by the sequential use of several web service methods. In many cases alternative web service methods are provided so that different software using disparate technologies can provide equivalent business functionality. An example of this feature richness is provision of support for different AMI applications that can determine the outage status of a customer service, one by directly querying the status of the meter (or “pinging” the meter), another by providing unsolicited report by exception functionality. Either capability provides equivalent business value. MultiSpeak supports a variety of web service methods so that a complete outage management business process can be constructed using either functionality. The web services are documented in openly-available WSDL files at http://www.multispeak.org/resources.htm .

In addition to the layered categories the GridWise Interoperability Framework includes cross-cutting issues that are appropriate for all of the categories. The cross-cutting issues are listed in Table 2.

All of these issues are important in concrete implementations, but many of the issues are addressed by existing standards. Where possible, MultiSpeak relies on existing industry standards and does not recreate necessary functionality. Thus, for instance, MultiSpeak relies on Secure Sockets Layer capability to provide security and privacy rather explicitly providing security services.

Table 2
GridWise Framework Cross-Cutting Issues

- Shared Meaning of Content
- Resource Identification
- Time Synchronization and Sequencing
- Security and Privacy
- Logging and Auditing
- Transaction and State Management
- System Preservation
- Quality of Service
- Discovery and Configuration
- System Evolution and Scalability

On the other hand, MultiSpeak specifically addresses (i) shared meaning of content, (ii) resource identification, and to some extent (iii) discovery and configuration. MultiSpeak provides clear definitions of what data objects mean and which objects are appropriate for passing specific information. Vendors of MultiSpeak-enabled applications can unequivocally rely on a shared understanding to provide context for interpretation of received data objects. Naming conventions and clear connectivity rules are established that unambiguously identify resources described in data exchanges. MultiSpeak also addresses discovery using specific web service methods that permit systems to identify what capabilities potential business partners support, the list of specific information types that can be obtained, and catalogs of codes or equipment lists used by other systems. Specific discovery or repository capabilities such as Universal Description, Discovery, and Integration (UDDI) are considered to be outside the scope of MultiSpeak, but can be applied as necessary on a site-specific basis.

3. MULTISPEAK IN OPERATION AT SAN BERNARD ELECTRIC COOPERATIVE

MultiSpeak has been in operation in utilities in some form for nearly seven years. Capabilities to support real-time business processes have been in operation for five years. San Bernard Electric Cooperative (SBEC), a rural electric distribution cooperative that serves about 21,000 consumers in coastal southeastern Texas provides an example of the power and flexibility of MultiSpeak interfaces. SBEC was an early adopter of real-time web services interfaces. SBEC has used MultiSpeak web services to fully integrate an outage management system (OMS) with an AMI used to detect customer outages, an interactive voice response (IVR) system used to take customer outage calls, and a SCADA system that can send device status changes to more accurately determine the cause of system disturbances. This level of integration enables the following capabilities:

- Outage calls taken by the IVR automatically show up as outages in the OMS.
- Customers, service locations and meters, obtained either from the AMI or a customer information system, can be correlated directly from the OMS display.
- The system dispatcher can determine the outage status of a meter directly from the OMS display, without the need to also run the AMI application. This capability can be used to determine the extent of an outage or to verify the restoration of a service without the need to send a line crew to the location.
- The AMI system can locate meters electrically on the system using information supplied by the OMS. Thus it is possible to address individual meters or meter groups that might be affected by the operation of a power system device, such as a distribution line fuse.
- The OMS automatically is provided with information about device status changes monitored by the SCADA system and thus can more accurately and quickly determine the cause of outages due to the lockout of a substation breaker.

Benefits gained from this integration include (i) enhanced customer service made possible by improved information about outage status, (ii) a reduction in outage time, (iii) a reduction in the "information overload" suffered by system dispatchers during extensive outages, (iv) a reduction in overtime wages during outages, and (v) improved employee efficiency. In addition, integration makes it possible to reduce the number of computer monitors necessary for the dispatcher to obtain the information required to handle a system outage, thus also reducing the number of application software seats and employee training on redundant applications.

A conservative estimate of the quantifiable savings gained from the integration of existing systems at SBEC is $111,533/year – which amounts to about $5.30 per customer per year. The specifics of San Bernard's implementation and the business process benefits gained may be found in reference [6].

4. IEC COMMON INFORMATION MODEL (CIM)

Technical Committee 57 (TC57) of the International Electrotechnical Commission (IEC) is also developing a standard for integration of utility software. The TC57 standard is based on an object model called the Common Information Model (CIM). CIM is documented in the IEC 61970-301 standard [7]. CIM was originally developed to support transmission and control centers, but is being extended to address all aspects of a vertically-integrated electric utility. As a result, CIM covers a wider field than does MultiSpeak, since currently MultiSpeak addresses only distribution.

Working Group 14 (WG14) of TC57 focuses on the distribution aspects of CIM. The extensions to the core CIM to address distribution issues are documented in the IEC 61968 series of standards. Of particular interest to this discussion are IEC 61968-1 [8], which outlines the basic architecture and message framework for distribution interfaces, and IEC 61968-11 [9], which outlines the information model for distribution interfaces. Since both address distribution issues, there is a substantial conceptual overlap in MultiSpeak and the 61968 standards.

CIM is targeted to larger investor owned utilities which typically have extensive information technology staffs and have more complex IT environments than are common among the electric cooperatives that are the target market for MultiSpeak. The CIM standards focus on message definition and content, leaving much of the transport and middleware as implementation issues. Such an approach would be inappropriate for smaller utilities and for the software vendors serving the cooperative market - many of which also have limited resources. As a result, MultiSpeak standardizes on web services as a means to transport data and does not assume the existence of a messaging middleware infrastructure.

5. A PROPOSAL FOR INTEROPERABILITY BETWEEN MULTISPEAK AND IEC CIM

One of the goals of GridWise that is clearly elucidated in the interoperability framework is the ability to "bridge between communities with independently evolved understandings". There is a clear need for building a semantic bridge between MultiSpeak and 61968 CIM so that eventually it will be possible to foster interoperation among MultiSpeak and CIM applications.

The ideal approach would be to use emerging semantic representation tools to provide a dynamic translation between MultiSpeak and CIM. The CIM community has recently begun to publish CIM in Web Ontology Language (OWL) format. MultiSpeak currently is considering making this step. It is believed that eventually tools will become available to facilitate electronic translation between semantic models expressed in OWL format; however, such tools are in their infancy.

A near-term approach would be to develop a translation adapter. Provided a mapping could be generated between the two data models, messages created using either standard could be electronically converted to the corresponding message generated by the other standard. That is to say, a translation table would be generated that indicates which pieces of data in a MultiSpeak message corresponded to which items in a CIM message, and vice versa.

This solution is achievable and consistent with the approaches already taken by the respective groups, as illustrated in Figures 1 and 2. Figure 1 shows the method used by MultiSpeak to allow two compatible software programs to exchange data, through a vendor-supplied MultiSpeak "translator" (indicated by the shaded ovals in Figure 1) without affecting the databases native to each piece of software. Many of the CIM implementations to date use an adapter layer to integrate a legacy application with CIM applications, as illustrated schematically in Figure 2.

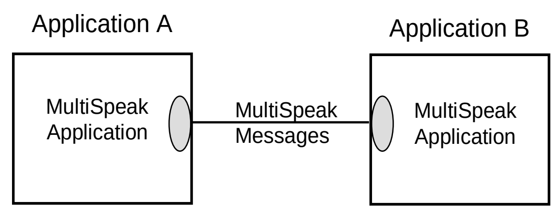

Figure 1
Data Flow between MultiSpeak-Enabled Applications

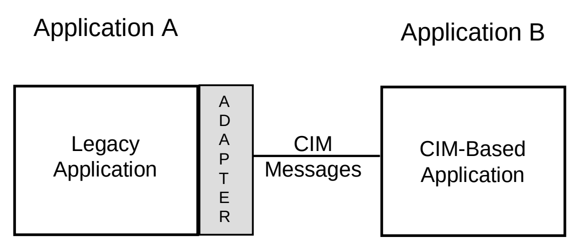

Figure 2
Data Flow between a Legacy Application and a CIM-Enabled Application

Figures 3 and 4 show conceptually how a translation might work between a MultiSpeak compliant application and a CIM compliant application. In either case, the adapter translates the output of the application to match the format expected by other applications on the network. Figure 3 is appropriate for the case where relatively few MultiSpeak-enabled applications are to be integrated into a predominantly CIM-based enterprise network; Figure 4 shows the case where relatively few CIM-based applications would integrate with a MultiSpeak-based enterprise network.

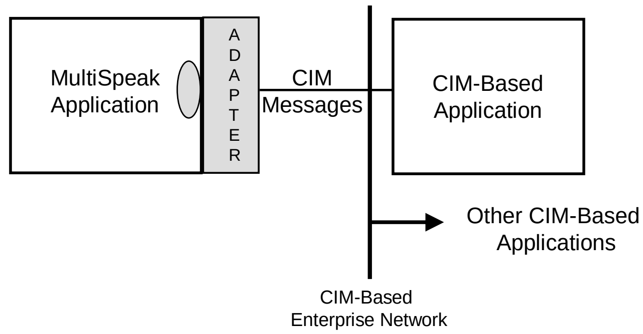

Figure 3
Integration of a MultiSpeak-Enabled Application into a CIM-Based Enterprise Network

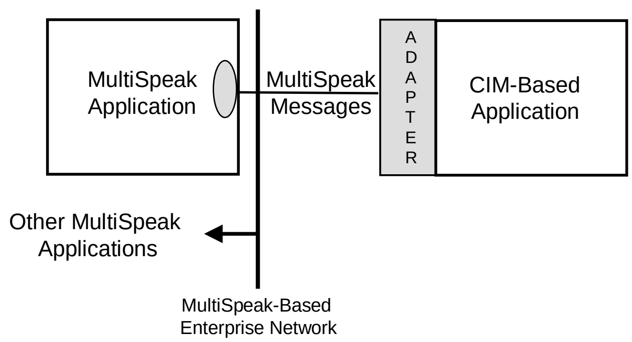

Figure 4
Integration of a CIM-Enabled Application into a MultiSpeak-Based Enterprise Network

Creation of the appropriate adapters requires several steps: first, a conceptual mapping between the two data models, and second, the development of an electronic translation using this conceptual mapping. Effort has begun in both MultiSpeak and WG14 to take the first steps to develop the conceptual mapping. It is anticipated that the creation of an XML style sheet translation should be straightforward once the conceptual mapping is completed.

6. CONCLUSIONS

MultiSpeak provides important capabilities that can assist utilities to implement interoperable enterprise networks. Many of the goals of GridWise can be achieved today with existing MultiSpeak interface definitions. MultiSpeak provides mature and complete functionality in support of AMI, meter data management, and other operational systems. Existing MultiSpeak functionality can easily be extended to provide the capability for AMI systems to return data from home networks or to control customer equipment, as the scope of these needs is further defined by the industry.

There is a great deal of conceptual overlap between MultiSpeak and the IEC 61968 extensions to CIM. Both standards have been applied in utility implementations and are likely to continue to be used going forward since each provides value to their respective markets. Thus, there is a need to develop a semantic bridge between the two data models. The authors have presented an approach to developing this bridge, which we believe is achievable in the near-term and will permit systems to flexibly evolve over time.

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Biography

Gary A. McNaughton is the Vice President and Principal Engineer for Cornice Engineering, Inc. He received a B.S.E.E. degree from Kansas State University in 1976 and an M.S.E.E. degree from the University of Colorado in 1980. Prior to joining Cornice in 1995 he worked as a Plant Electrical Engineer for Union Carbide, at the Oak Ridge Gaseous Diffusion Plant, at Oak Ridge, TN, as a Transmission Planning and Protection Engineer for Colorado-Ute Electric Association, a generation and transmission cooperative, located in Montrose, CO, and as Staff Engineer, Manager of Engineering, and Assistant General Manager for Engineering and Operations for La Plata Electric Association, in Durango, CO. Mr. McNaughton currently serves as the Project Technical Coordinator for NRECA's MultiSpeak® Initiative. Mr. McNaughton is a registered professional engineer in the State of Colorado.

Robert Saint is a Principal Engineer in the Technical Services Division at the National Rural Electric Cooperative Association (NRECA). Mr. Saint graduated from Wichita State University, in Wichita, Kansas, with a BS degree in Electrical Engineering. Since graduation he has worked for electric utilities in Texas (2½ years) and Colorado (22 years). He worked for Tri-State G & T for over 5 years primarily performing substation design and 17 years with distribution cooperatives in Colorado. He is a registered Professional Engineer in Texas and Virginia. At NRECA his primary role is technical advisor for the T & D Engineering Committee. The subcommittees he works with are Power Quality, Substations, System Planning and Transmission Lines. He is also the liaison for the E & O Committee on Cooperative.com and the Program Manager for the MultiSpeak® software integration initiative.

Implementing the Smart Grid: Enterprise Information Integration

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Keywords: Smart Grid, Enterprise Integration, Data Assets, Utility Applications, Systems Implementation

ABSTRACT

This paper presents some of the merging Smart Grid applications and discusses information systems requirements for a broad-base implementation of the Smart Grid applications. It provides representative examples, discusses existing challenges, and presents considerations for enterprise level implementation and integration of information systems in support of Smart Grid initiatives.

1. DRIVING FACTORS FOR SMART GRID

Some believe that the electric power system is in a process of a profound change. This change is driven by the convergence of information and power delivery technologies, and by the need for energy conservation and concerns regarding climate change. The changes are particularly significant for the electric distribution grid, where "blind" and manual operations, and electromechanical components of the previous century are being transformed into a "Smart Grid" by digital instruments, two-way communications, and automation.

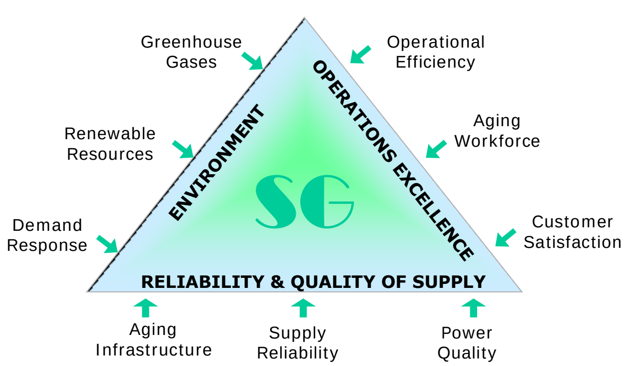

Figure 1 Driving Factors for Smart Grid

The key business drivers for the Smart Grid include:

Reliability and Quality of Supply: Our society is critically dependent on a reliable supply of electric power. The ageing infrastructure of our transmission and distribution networks threatens the security, reliability and quality of supply. Significant improvements in the reliability of power supply can be achieved through improved monitoring, automation and information management.

The Environment: Environmental issues have moved to the forefront of the utility business with concerns regarding the greenhouse gases and its impact on climate change. Many envision greater penetration of renewable resources closer to end-use consumption, and greater reliance on demand-side management and micro-grids.

Operational Excellence: Faced with the need to further improve operational efficiencies, utilities must deal with challenges associated with an aging workforce, and expectations for flexibility and improved services by regulators, customer and the market place. Utilities realize that they must shift their traditional business practices from a dependence on incumbent-based knowledge to systems-based knowledge through information management and automation.

2. THE BUILDING BLOCKS OF SMART GRID – THE SG ENABLING STACK

A "Smart Grid" vision is achieved by bringing together enabling technologies, changes business processes, and a holistic view towards the end-to-end requirements of the grid operation. We call this the Smart-Grid Enabling Stack.

Customers, consumer-side capabilities and distributed generation technologies from the base of the stack. These includes demand side automation, in-home networks and energy management systems, as well as distributed generation technologies, e.g., solar photovoltaics, plug-in vehicles, and other storage devices. The base is supported by smart meters, and intelligent monitoring, switching and control devices, as well as distribution automation technologies as an integral part of the power distribution grid. These devices, meters and controls are inter-connected through a utility-wide, and two-way data communications networks connecting customers, distributed resources and field devices with the enterprise systems and applications. This enables a broad-based demand response and distributed resource management, and it supports a self-healing grid operation.

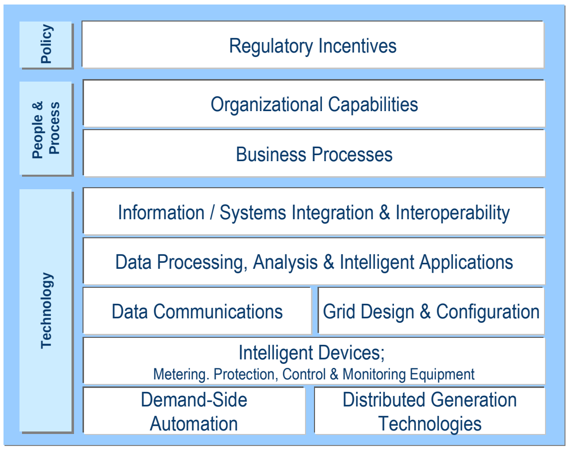

Figure 2. The Smart Grid Enabling Stack

Enhancements to distribution grid design and configuration may also be required to fully support the ever expanding penetration of distributed resources and accommodate grid automation.

Supporting these base layers is a myriad of information processing, analysis and software applications to provide the necessary intelligence and to support of various utility and customer facing operations of the Smart Grid (SG). A critical element of the SG Stack is information and systems integration to enable coordinated decision making and operations, and to enhance the overall operational efficiency and system reliability.

These technology layers need to be supported by organizational, people and process capabilities. The current utility operational processes were designed decades ago when we had limited available information and automation, and significantly relied on manual inspections and operations.

Finally, due to the regulated nature of the power industry in North America, regulatory policies and incentives are critical to major initiatives in this area. Market forces and shareholder sentiments also play an increasingly important part in grid modernization and Smart Grid initiatives.

The following sections will elaborate on the systems integration and interoperability issues layer of the Smart Grid Stack.

3. SYSTEMS INTEROPERABILITY

Utilities have implemented various pilot projects and limited scope deployments of Smart Grid applications with a minimum impact on existing operations and systems. However, a large scale Smart Grid initiative will have an impact on many utility systems and processes spanning over customer services, system operations, planning, engineering and field operations, and even power supply functional unit of a utility business.

Systems interoperability, information management and data integration are among the key requirement for achieving the benefits of Smart Grid. Automation and intelligent operations will require timely and accurate data, and the need for operational efficiencies demand coordination, orchestration and synchronization of information used by various elements of the utility operation.

Figure 3 provides a conceptual view of the typical suite of applications and system components involved in support of

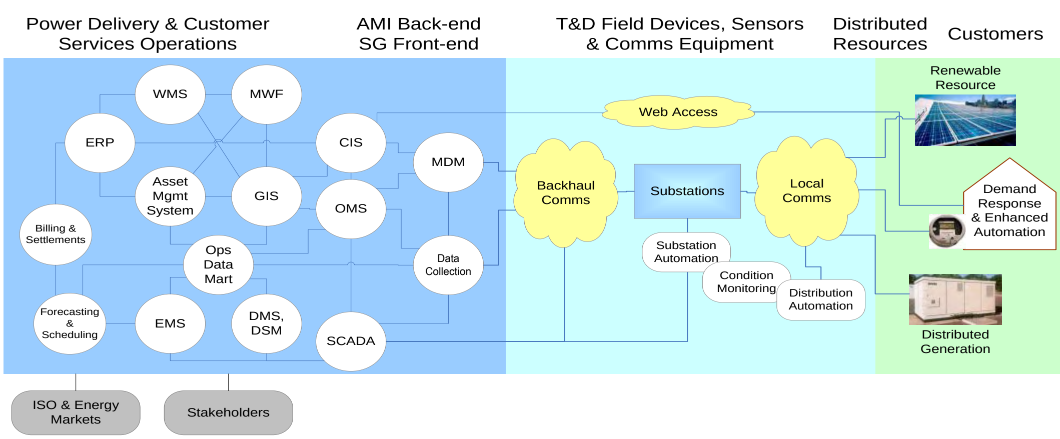

Figure 3. Systems impacted by Distribution Smart Grid

a "smart" distribution grid operation with a reasonable penetration of distributed resources, distribution automation, and Advanced Metering Infrastructure (AMI). As can be seen, in addition to advanced metering and communications infrastructure to support demand response, distributed resource management, automation functions, the deployment is also involves a number or enterprise and operational software applications and information systems.

The following subsections provide some example requirements and impact scope for large scale Smart Grid applications.

3.1. Example: Improved System Reliability

Utilities have experienced significant improvements in system reliability through deployment of a fully integrated outage management system that brings together trouble call, customer information, network connectivity, as operated filed data, and geo-spatial information. Use of last gasp data from AMI meters in real-time, and the capability to verify service delivery and restoration through the AMI communications infrastructure can significantly reduce the time for outage detection and service restoration. As shown in Figure 4, this will require integration of the Outage Management System (OMS) with a number of other applications, including AMI and supporting meter data management system (MDMS), GIS, Customer Information System (CIS), work management system, and SCADA/DMS, as well as distribution automation (DA) functions.

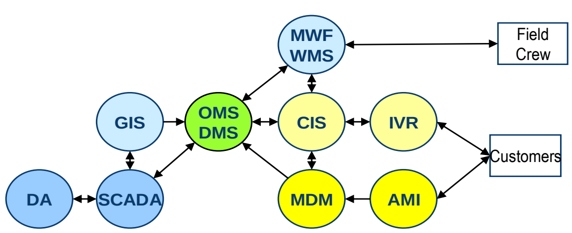

Figure 4. Interoperability requirements for Outage Management

A utility's outage management performance is typically measured by the System Average Irruption Duration Index (SAIDI) or Customer Minutes Lost (CML). Figure 5 illustrates a representative set of SAIDI values of for selected US and overseas utilities. US utilities have a benchmark of 120-160 minutes for SAIDI. European utilities typically have a higher degree of automation on their distribution network, thus the average system interruption duration, CML, in Western Europe is around 60-80 minutes. Some utilities in Asia operate based on a CML target of 5 minutes or less. These utilities have a significantly higher degree of monitoring and control capabilities on their distribution system, and have a higher degree of reliance on automation than their US counterparts. Some leading utilities in Asia, e.g., TEPCO, strive for a CML (SAIDI) of less than 5 minutes with extensive self-healing grid design and automation technologies.

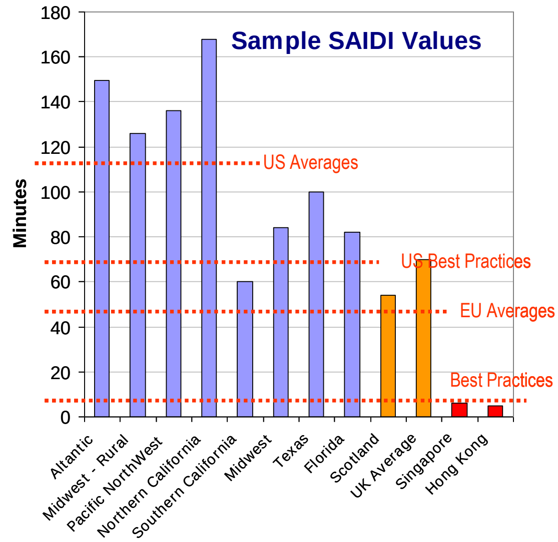

Figure 5. Representative SAIDI Values

As is illustrated above, there is significant room for improvement for the US utilities.

3.2. Example: Large Penetration of Distributed & Demand Side Resources

Today's electricity grid is designed based on a vertically integrated supply model with dispatchable centralized generation and distributed consumption with no generation resources on the distribution network. Distribution networks tend to be radial with mostly unidirectional power flows and "passive" operation. Their primary role is to deliver energy from the transmission substation down to the end-users. The design and operation of distribution grid has not changed much over the past three to four decades.

We believe that over the next decade, a proportion of the electricity generated by large conventional plants will be displaced by distributed generation; renewable energy sources; demand response; demand side management; and energy storage. Thus the Smart Grid of the future will need to accommodate more intermittent and decentralized generation, and support bi-directional power flows. In addition, distribution system may require stand-by capacity which could be called upon whenever the intermittent resources cease to generate power.

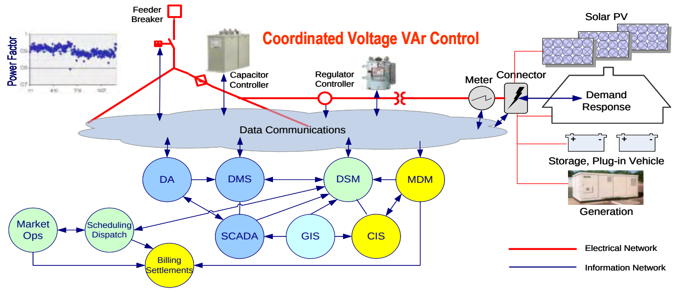

Figure 6. Systems interoperability with substantial penetration of distributed resources

The distribution grid of the future will require significantly higher degree of automation to ensure reliability and quality of the power supply. Coordinated voltage and VAr control, automated switching and relay coordination and extensive monitoring will be a necessity. The electricity grid will be interactive for both power generation sources and power consumption sinks. Enabled by in-home automation, smart metering, modern communications and the increased awareness of customers, demand side management will play a key part in establishing new services that will create value for the parties involved.

Operating a power delivery network with a substantial penetration of distributed resources will require considerable changes to the existing network operating practices. As illustrated in Figure 6, many of the information management functions involved with distribution management and automation, operations planning, scheduling and dispatch, market operations and, billing and settlements will be impacted.

The electricity distribution network needs to be supported with an information management network that may play an equally important role for delivery of electric power to end-use customers. The information network will brings together the diverse data needed to manage generating and demand resources on the distribution network while maintaining power quality and reliability.

3.3. Example: Asset Management

Another important aspect of a Smart Grid is how the transmission and distribution assets are managed and maintained to ensure a high degree of system reliability while optimizing Operations & Maintenance activities. Coordinated asset management, equipment condition monitoring, condition-based inspection and maintenance, dynamic adjustment of operating limits and equipment rating based on their condition are among the strategies that a modern grid operation needs to employ. These strategies improve O&M efficiencies, extend equipment life and improve maintenance processes. This in turn results in enhanced system capacity and improved system reliability.

These objectives require smart monitoring devices, data collection and conversion of the data to information, and taking action based on that information. A system-wide deployment of asset management strategies will require integration of data from such systems as SCADA, meter data management, GIS, Supply Chain (ERP/AM), and coordination of those data with work management, mobile workforce, as well as EMS, DMS and OMS applications.

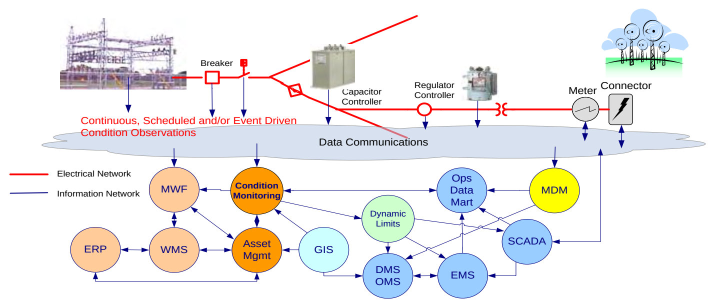

Figure 7. Systems Interoperability needs for Asset Management

4. ENTERPRISE LEVEL INTEGRATION – DATA ASSETS

Currently most utility companies have limited installed capability for interoperability across the applications associated with system planning, power delivery and customer facing operations. In most cases, this information in each organizational “silo” is not easily accessible by applications and users in other organizations. These “islands of information” corresponded to islands of autonomous business activities. The Smart Grid strategy calls for enterprise-level integration of these islands of information to improve information flow and work throughout the organization. It is important to provide a single, consistent view of information throughout the organization, making enterprise data accessible securely and in a timely fashion to authorized users across the enterprise.

There is an emerging trend to treat information as enterprise asset. These assets need to be properly managed, controlled and made available to different users and applications across the enterprise. For example, the network connectivity and spatial data in GIS are needed by many applications, e.g., Outage Management System (OMS), mobile workforce (MWM), Customer Information System (CIS) for customer mapping, systems planning and engineering in support of asset management and network analysis, and by SCADA for world-maps, etc.

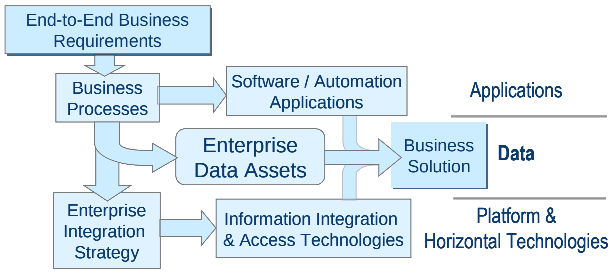

Figure 8. Key process elements for integrated Smart Grid information management

A key requirement for information integration and management across the utility operations, especially in the context of Smart Grid, is the definition of the Enterprise Data Assets. This is data that is accessed and used across the enterprise by business operations and systems. Figure 8 illustrates the key process elements in deployment of integrated Smart Grid solutions. As can be seen data management and data integration play a central role in creating an integrated business solution. The accuracy, integrity, reliability, timeliness and accessibility of these data assets are critical to the "smart grid" operation.

A simplified illustration of the data assets concept is provided in Figure 9. A key requirement for the data assets is the establishment of the System of Records (version of truth) for these assets. A formalized and comprehensive data management principles needs to be established to manage these assets.

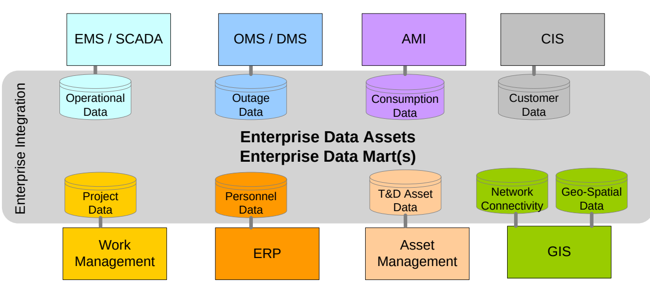

Figure 9. Key operational Data Assets

The key elements of the data management principles include:

Data Stewardship – to define the data ownership and its Chain-of-Custody;

Data Organization – to establish data modeling and definition standards, and to define the System of Records for the enterprise data assets;

Data Content Management – to establish processes and responsibilities for data update, maintenance and quality management;

Data Access – establish methods, and tools for data access including data security and availability; and

Data Presentation – including visualization and data transformation, as well as business intelligence required to covert data to useful information.

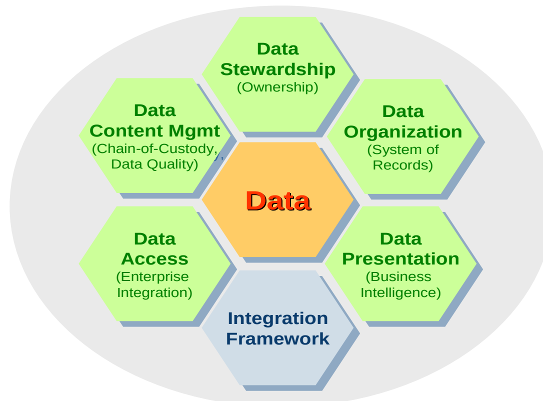

Figure 10. Enterprise Data Asset Management Principles

Traditionally, data was an embedded part of an application. For example, SCADA data was only accessible through SCADA operator consoles, reports and data export capabilities. In the case of SCADA data, many utilities have used a separate data warehouse moving the data from the SCADA system to a separate repository for access by other enterprise users. This concept can be generalized through creation of enterprise level data marts to bring together the information needed by operations across the organization. Such data marts can be physical or virtual, i.e, a separate physical database, or a federation of databases associated with different applications.

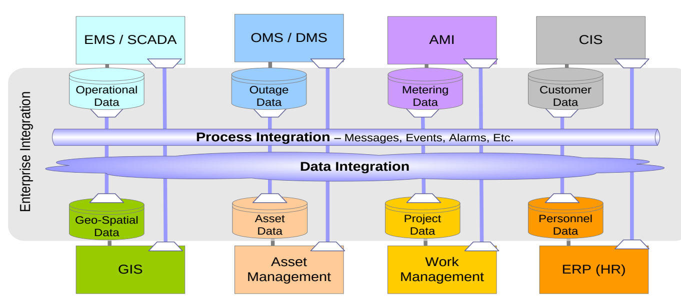

Figure 11. Enterprise Information Integration

Implementation of Smart Grid will require integration of processes and information across a multitude of systems and applications within utility system operations, planning and engineering and customer services. The technical integration activities will include integration of data and messages associated with real-time events, alarms and other notifications that require immediate attention, and integration of data associated with assets and networks, their configuration, condition, and other operational and business data that can be accessed across the enterprise on a bulk or transactional basis. Thus, on a conceptual basis, the enterprise level information integration for Smart Grid applications can be sub-divided into two general classes: 1) real-time notifications, control and process integration, and 2) bulk and transaction based data exchange amongst different applications. For example, the exchange of network connectivity models between GIS, DMS, OMS and planning applications can be considered as a bulk data transaction, where notification of an outage can be considered as a real-time event.

There are many techniques, technological solutions and vendor offerings for enterprise-level information integration, including various middleware message bus products, web services and other technologies and tools for systems integration under a service oriented architectures (SOA). A key industry challenge at this stage is the lack of broadly developed and supported reference models and standards for integration of field devices, smart meters, renewable resources with software applications integration, and applications interoperability in the distribution space.

Some of the existing industry standards efforts e.g., IEC TC57: IEC61850 for Substation Automation, IEC61968 for Distribution Management Systems – IEC61970 for Energy Management Systems and Common Information Model (CIM) provide some framework for this, but they are not fully adopted and supported across the industry. Other IEEE, ANSI and other regional and utility standards for network design, distributed generation interconnections, and operations also exist, but may present certain limitations when dealing with the broader Smart Grid requirements.

5. ROADMAP FOR SMART GRID IMPLEMENTATION

Many utilities have initiated strategic plans for modernization of their power delivery and distribution operations. This is in part influenced by the synergistic capabilities of AMI technologies, especially its ubiquitous two-way communications capabilities. Also the need for improved system reliability, enhanced operational efficiency, and support for distributed resources as well as demand-side programs are also driving the modernization needs. The roadmap to implementation should consider the following:

Strategic Planning - Smart Grid requires a coordinated phased implementation and roll-out plan spanning over several years covering design, implementation and change management.

Regulatory Strategy – Strategies for cost recovery and regulatory alignment.

Holistic Approach – Smart grid requires a holistic approach to operations and business surrounding systems planning, power delivery and customer services. It requires a transformation away from a “Silo-Based” Business.

Business Case Justification – It requires a sound business case regarding costs and benefits associated with technologies and business transformation. Leveraging project synergies is a critical factor to the business case justification.

Enablers and Foundational Capabilities - Identification and implementation of enabling and foundational capabilities, including people and process, are critical to the long-term success of these initiatives.

Interoperability Standards – Establishing enterprise level governance, adopting interoperability standards and developing an architectural framework for data, systems and technology integration is an important step in implementation of Smart Grid initiatives.

Practical, Balanced and Leveraged Solutions – The need for business continuity and that leverage existing investments demands practical solutions that augment current capabilities and interoperate with existing systems and processes.

The future models for the Smart Grids have to meet changes in technology, and accommodate public values related to the environment and commerce. Thus security, reliability, safety, environment, power quality and cost of supply will all be examined in new ways and energy efficiency in the system will play an increasing role in balancing the system. The industry has already embarked on this journey the length of which will be determined in large part by how well all the players and decision makers understand the costs and benefits of modernization.

Biography

Ali Ipakchi has over 29 years of experience in delivering system solutions and services to the electric utility industry. He has assisted utility clients with specification, design and deployment of automation and information technologies for improved grid operations. Dr. Ipakchi is an industry leader in development and promotion of Smart Grid concepts, and has helped utilities with strategic planning, cost benefit assessment and deployment road map for technologies needed for Smart Grid operations. Prior to joining KEMA, he held a senior management staff position at a leading T&D vendor responsible for key software products development and delivery. He has managed many large IT projects leading engineering and technical teams.

Dr. Ipakchi is co-holder of three US patents on power systems applications and instrument diagnostics.

He has a successful track record of helping major organizations expand business and, develop products and services with his strong technical and business management skills. He brings extensive IT systems experience for utility T&D operations including system control centers, distribution operations, customer care, market operators, trading floors, and merchant power operation centers.

Interworkability: The Key Ingredients

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Keywords: Interoperability, Interworkability, Standards, Integration, Architecture, Distributed Computing

Abstract

Interworkability, the ability of two or more devices to interoperate on deeper levels, will take significant cooperative efforts to achieve. In addition to formal standards, user based technical agreements and a merging of management infrastructures is also required. This paper covers a few of the major ingredients that will be necessary to fulfill the vision of fully integrated systems. Critical among these ingredients is the right mix of cooperation and integration across a number of standards and consortia working the problem.

1. INTRODUCTION

The fully integrated future intelligent power system complete with dynamic and automated customer systems will be challenging to develop on the envisioned scales. Interworkability goes beyond interoperability in that it includes the ability of the equipment to do most of its own management as well as correctly execute applications for the everyday users. As systems become more complex and scale up to tens of thousands if not millions of intelligent devices, the key elements for interoperable and interworkable systems become increasingly important for both capital cost and life-cycle cost management.

1.1. Realizing the need for infrastructure

Too often the perception of building an automation system is taken as just a matter of going to the nearest automation conference and specifying systems with a shopping cart. Blindly buying systems offered with the hopes of taking them back and integrating them at any level is wishful thinking at this time. Yes, it is a future vision that we will be able to someday integrate systems by just plugging them into a communications network. However, the so called “plug and play” promise is yet a good distance off for many systems and components offered in the utility automation and customer communications marketplace. This vision has been put forward so much over the last 20 years that people think it will happen by magic. It will not. The industry needs to realize the need for and then work toward the development of not one but several infrastructures. Moreover, these systems need to be specified, developed, tested, deployed and managed as well as possible at the start.

2. INTEROPERABILITY AND INTERWORKABILITY

Interoperability requires agreement. Agreement between equipment as integrated over a network requires not just agreement at all the implemented layers of the OSI Basic Reference Model but also within the Layers above layer seven. This includes how the applications carry out instructions as well as how they assist with initial configuration and ongoing system administration. Another dimension to interoperability is the more involved term interworkability that includes the exchange of meta data and the ability of equipment to support more “plug and play” type set up and integration. Interworkability includes not only the ability to accurately send and receive messages over the network but also be able to correctly interpret and execute the messages in a distributed computing environment where the application could be executed on multiple devices across a network. Equipment that interworks carries a higher standard of execution requirement particularly in a “real-time” control environment where the application must execute within a defined window of time. The term Interworkability is associated with the Manufacturing Message Specification (MMS) Standard also known as ISO 9506. Understanding the execution environment is important to the development of interworkable equipment and applications.

3. STANDARDS DEVELOPMENT

3.1. Standards Development

The development of well thought out standards that are based on a body of industry knowledge is a starting point for developing interoperable systems. The power industry will need to orchestrate a variety of standards for implementing intelligent systems on the scales now envisioned. Standards are of two types: defacto and dejure.

Defacto standards emerge from sheer strength of presence in the marketplace while dejure standards are developed typically through contributions to Standards Development Organizations (SDO's). SDO's are typically accredited through an organization overseeing the processes to ensure open participation and systematic addressing of issues as the standards develop. Standards from recognized SDO's provide a measure of stability within technical standards so that vendors can build products and have a reasonable expectation of product life-cycle.

3.1.1. Standards Participation

Participation in the standards process must go beyond attending meetings. It is the work between meetings that results in modifications or suggested improvements to the standards that provides the raw material for the maturity of standards. In particular extensions of existing standard specifications in response to new applications are one of the key sources of enhancements. In addition, many improvements also come from efforts to apply the standards for new applications and equipment. Many useful contributions to standards have come directly from projects developing applications. Key research and development projects can play a critical role in doing this type of work that not only develops the equipment but also contributes to improvements to the standard.

3.1.2. User Groups and Consortia

User Groups and Consortia that are associated with an SDO based standard have the complementary roles of resolving technical issues. These are sometimes called "Tissues" by insiders. In addition user groups will take on the task of standards conformance testing. Conformance testing is not a job performed by formal SDO's, though they may become involved with assisting in the specifications for conformance testing. For the power industry the UCA International User Group has a subcommittee on testing and supports development of quality assurance procedures for use of the IEC 61850 Standard. Similarly the ASHRAE BACnet Standard for Commercial Building Automation has several user groups world wide and includes a manufacturers group.

An active user group is an important ingredient in developing equipment that not only conforms to a standard but also interoperates across the vendor equipment offerings. User groups often get involved with the development of technical implementation agreements that further define how the standard should be applied for truly interoperable/interworkable equipment and applications. These agreements are necessary when the standard contains allowable vendor specific options. These options are in part due to the standards consensus processes but may inhibit interoperability. These agreements in turn may be contributed up to the supporting SDO for adoption as a companion standard or may remain a less formal user community agreement.

4. SYSTEMS ENGINEERING

For robust systems development, systems engineering methods should be applied to any project. Systems engineering provides a systematic approach to the development of requirements, documentation and ultimately the management of advanced automation systems. Any system will require rigor to first adequately specify both the function as well as the non-functional requirements necessary to specify systems. Interoperability and interworkability must be built into system specifications from the start. Systems engineering must be applied with other technical disciplines within the application domains such as electrical engineering, telecommunications engineering and software engineering. Systems engineering is particularly important to help specify robust systems that can last for many years in the field. This is another important ingredient in the development of interoperable and interworkable systems.

5. RESEARCH AND DEVELOPMENT

R&D is another necessary ingredient in the development of interworkable equipment and applications. There are a number of remaining unresolved issues in the development of robust advanced utility automation systems. Some of the areas still remaining include the following:

5.1. Network Research

Several issues in next generation network management infrastructure need to be yet worked out. Large scale addressing, multihoming and integration of management functions over a variety of physical media are remaining issues. The sheer scale of millions of managed networked components poses significant network and systems management issues that remain to be fully addressed.

5.2. Cyber Security Research

Developing robustness into massively scaled networks remains an issue as well as developing new technologies such as real time intrusion detection, and robust security management

5.3. Development of Tools and Methods

Tools and methods for specifying and documenting future systems is also an area that needs further R&D. Methods are needed to adequately describe architectures. Refining and adopting a model of industry operations is the subject of ongoing work. New areas of complex systems engineering are just beginning to emerge.

5.4. Data and Device Models for Advanced Equipment

Uniform and standardized application level communications are still in development and are necessary for the development of interoperable equipment. This need is especially acute for residential in-building appliance and equipment integration.

5.5. Designs and Initial Implementations

R&D is also important for initial equipment designs and "bench top" implementations of applications and equipment built to emerging standards. A critical element of standards development for interoperable equipment is the development of real equipment. This work is the refinery for standards maturity since it brings out areas in the standard that are ambiguous or where standards need to be extended for specific functions.

5.6. Initial Field Trials

R&D also has a role in the execution of initial field trials. This is also an area of key importance to the development of standards since it places them in real world situations and user experiences. These trials will also reveal issues that once resolved can assist the development of the standard, interoperability agreements and the achievement of interoperable equipment.

6. ARCHITECTURE DEVELOPMENT

Architecture development is yet another critical area of development for interoperable equipment. Architectures by definition view the issues from a higher plane than standards development. Architectures are concerned with the following ingredients that are necessary for interworkable equipment on an industry scale.

6.1. Integration of Standards

Another dimension of interworkability is the scope and extent of integration achieved across the enterprise or even an industry. Architecture development includes the necessary integration of standards for applications that must integrate systems across the enterprise as well as integrating with other entities. For utilities, operations will integrate with customer systems as well as with Independent System Operators. The integration of standards at the level of industry architectures are another key ingredient for future interworkable systems.

6.2. Model Development

An industry model of operations in conjunction with the development of requirements and key standards represents another key ingredient to bring the vision of integrated systems. Models have provided an indispensable tool for the telecommunications, aerospace and other key industries. It is a tool that will contribute to the development of interworkable systems and equipment

6.3. Architecture Development

Architecture development is still maturing as a discipline and will likewise contribute as a key set of ingredients for the power industry as it moves forward. Presently, the tools and formal descriptions of architecture are still under development. This area promises to contribute to the larger scale issues of interworkable equipment over the long term

7. TECHNICAL TRANSFER

Transfer of the "technology of integration" needs to take place within the following audiences:

7.1. Transfer of Technology to Utilities and System Integrators

Utilities and energy service providers will be the integrators of the envisioned future systems. Transfer of the technology of integration is important for correctly specifying, procuring, accepting and managing the next generation of advanced equipment over its life-cycle.

7.2. Transfer of Technology to Vendors and Equipment Developers

Technology of integration also needs to transfer to the vendor communities as they design and build the equipment for the next generation of utility automation. Transfer is through the formal standards as well as the user groups and paying attention to emerging industry requirements trends.

7.3. Open Source

Open source computer code that represents a consistent approach to implement a given standard may play an increasing role in future systems development. This is an emerging area of technical transfer but one that shows promise for open standards based automation equipment.

8. CONCLUSION

Interworkable applications and equipment will take a blend of key ingredients to enable the future visions for the industry. The encouraging part of these scenarios is that significant work has already been completed and much that can be built upon. In addition the numbers of communities that are starting to support the concepts of open systems and standards based equipment are growing. Significant work remains but through cooperation in standards user groups and research efforts the visions of interoperable systems can be manifest.

Biography

Joseph Hughes is a research project manager for the Electric Power Research Institute in Palo Alto, California. Mr. Hughes has over 25 years in R&D in the power industry Mr. Hughes is a member IEEE and active in IEC and other industry standards and consortia.

The Missing Piece in Achieving Interoperability – a Common Information Model (CIM)-Based Semantic Model

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Abstract

The IEC 61968/70 Common Information Model (CIM) standards lay the foundation for an enterprise semantic model to achieve interoperability. Key aspects are discussed, including the importance of defining standards boundaries at the right level of abstraction to ensure adoption and continued use in the face of changing information infrastructures and systems, and how unique business contexts based on country and enterprise practices can be incorporated without over-defining the abstract information model standard. The importance of focusing on interfaces for application of semantic model standards and especially for testing for interoperability and compliance is stressed as well as the role of EPRI in extending the CIM into new areas where interoperability is needed and in interoperability and compliance testing to ensure products comply with CIM standards. The key role of profiles and messaging standards to establish interface contracts are explained as well as a related standard, the Generic Interface Definition (GID) for defining interface services.

1. THE NEED FOR SEMANTIC MODELS

The missing piece in most interoperability frameworks is agreement on a semantic model, which is arguably the most strategically important piece of any interoperability solution. This holds true whether one is dealing with system interfaces, field device data reporting, or human interfaces. The need to ensure understanding and avoid confusion in interpreting data while at the same time facilitating the sharing of data among distributed independently-developed applications is common to all enterprises.

1.1. Current Approaches to Achieving Interoperability

Most interoperability frameworks found at utilities today either were built from the ground up as new system interfaces were identified or designed around some type of Enterprise Service Bus (ESB). In either case, the resulting integration framework is defined primarily by the physical connectivity solutions adopted, with information integration typically being handled on a case-by-case basis by the project teams responsible for the particular system interfaces involved. This type of information integration requires unique mappings between every pair of system interfaces, resulting in transformation logic that resides either in a centralized ESB server or at system interfaces.

While Service Oriented Architectures (SOAs) are a step in the right direction by providing a common set of services for information exchange that are independent individual systems involved in the exchanges, they do nothing in and of themselves to address the information integration issues.

1.2. The Role of Semantic Models

At the other end of the spectrum are Model Driven Integration (MDI) frameworks based on a common semantic model that provides the starting point for all information exchanges. That is, any file or message payload defined for the exchange of information between two systems will contain data elements derived directly from a common semantic model, thus ensuring information is integrated regardless of the source of the data. This leads to the adoption of an adapter architecture which provides the transformation logic to map from proprietary data representation to a common model representation in an adapter between each system and the enterprise bus. The big advantage of this approach is that each system has only one mapping (i.e., native to common model), facilitating information sharing, since the source of the data no longer defines the semantics and syntax of the data.

1.3. The Business Case for a Common Semantic Model

While the importance of a common semantic model to system integration cannot be underestimated, the real business value comes from the composite business intelligence and decision support applications that it enables. These applications require data from a variety of sources, but without a common semantic model, they cannot be counted on to deliver on their promise of improved quality of decision making.

1.4. The Need for Enterprise Information Management

With such clear business advantages, it would seem like adopting an interoperability framework based on a common semantic model would be obvious. However, the reality is that it takes advanced planning at the enterprise level to make it a reality. This involves several inter-related efforts:

1. Definition and adoption of an appropriate reference architecture that embraces the notion of a common semantic model.
2. Development of an enterprise semantic model.
3. Establishment of a governance policy for the management and maintenance of this model as well as methodologies to create information exchange models that are based on it.
4. Organization of IT resources to assist individual projects in implementing the policies and procedures necessary to implement system interfaces based on the model. Without strong incentives from the enterprise level, individual project managers will find it difficult to enforce its use due to vendor push back citing increased cost over continued use of proprietary interfaces.

In current industry thinking these are all necessary ingredients of Enterprise Information Management (EIM) plan, which is defined by Gartner as “An organizational commitment to structure, secure and improve the accuracy and integrity of information assets, to solve semantic inconsistencies across all boundaries, and support the technical, operational and business objectives within the organization's enterprise architecture strategy.” The key to successful implementation of EIM is having a plan in place before any of these individual efforts are undertaken. A well thought-out plan will provide clear boundaries between the various roles and responsibilities as well as a methodology for definition of the reference architecture and enterprise semantic model. It should also identify the role of standards in these activities.

The remainder of this paper deals exclusively with points 1 and 2 above. Concepts presented are loosely based on References 1 and 2 with regard to the layered architecture and bridging from UML to OWL to other sources of information, respectively. However, it is of critical importance that all aspects of an EIM strategy be kept in view if the benefits of a common semantic model are to be realized.

1.5. The Role of Standards

Standards can play a vital role in several areas:

1. Definition of a layered reference architecture, clarifying the boundaries between standards in each layer.
2. Provision of a vertical industry information model that can be a key part of an enterprise information model
3. Definition of generic services for information exchange
4. Definition of profiles for the services and semantics for specific information exchanges between business functions

Fortunately for the utility industry, standards addressing these areas have been developed under the initial sponsorship of EPRI. The IEC 61968/70 series of standards define a Common Information Model (CIM), a set of generic services, a set of profiles and message definitions for information exchange. The CIM standards have been developed, managed, and extended by and for utilities, vendors and consultants to ensure completeness and acceptance. While a standard can never address all the information needs of a utility enterprise, it can provide a starting point, and if managed properly, it can be extended via private extensions and later via adoption into the standard.

The layered reference architecture referred to above is the focus of a concentrated effort in IEC Technical Committee 57, Power System Management and Associated Information Exchange, to provide a structure for the deployment of these standards as well as to provide guidelines for the development of standards for the individual layers.

2. STRATEGY FOR BUILDING AN ENTERPRISE SEMANTIC MODEL

One of the key aspects of a successful strategy in building an ESM is to define a reference architecture or framework to show how the various pieces that comprise the ESM all come together to provide model driven integration solutions.

2.1. A Layered Architecture

Figure 1 illustrates a three layered reference architecture that provides clear boundaries between the functions provided in each layer. This reference architecture is useful both for guiding the development of standards for each layer as well as for the development of an ESM within a particular utility. Regarding the standards-related use, this architecture embraces concepts that are currently being adopted into the CIM standards to provide a more stable yet flexible set of standards that can be adapted to a variety of environments.

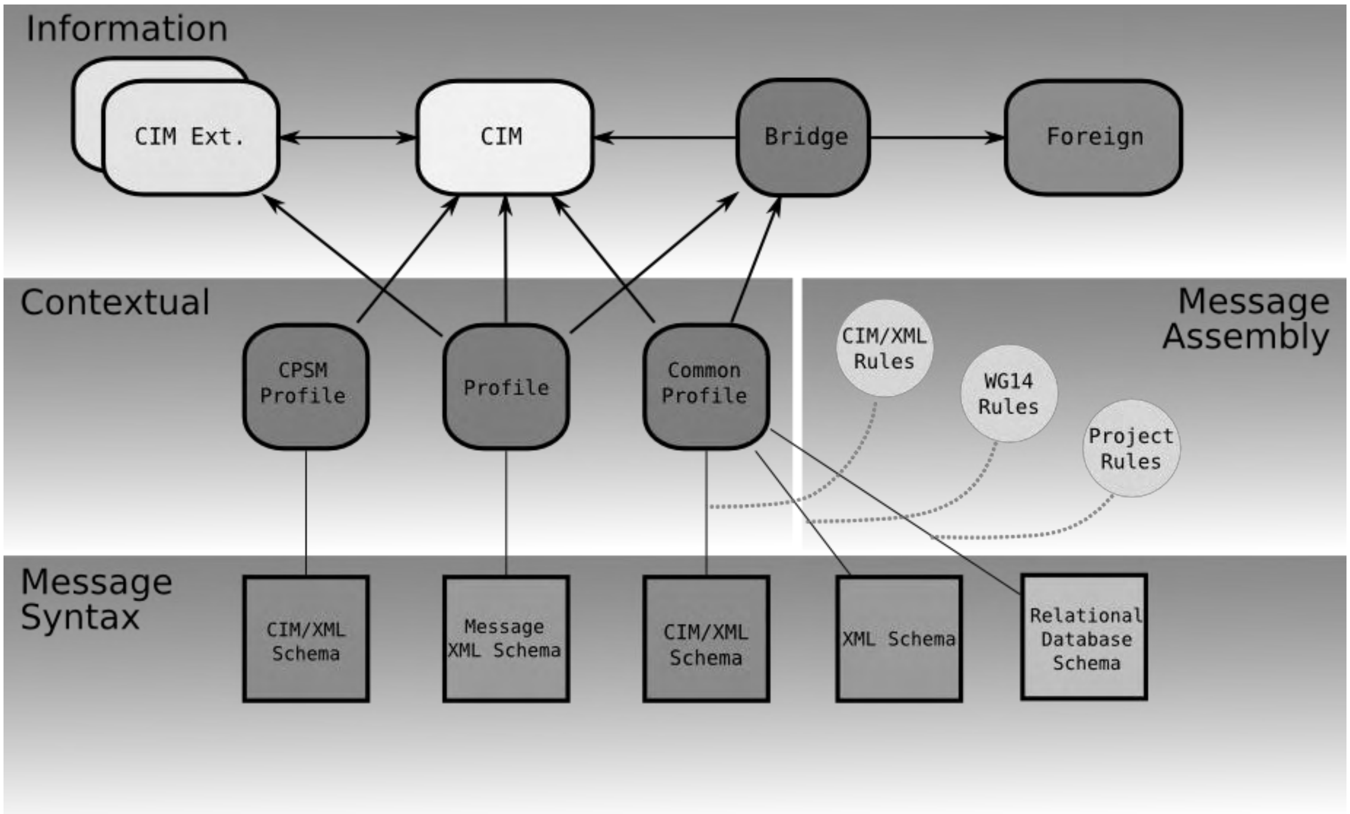

Figure 1, ESM Reference Architecture

The individual layers comprising this reference architecture are:

Information Layer – This layer includes the CIM but provides for the reality that there are other sources of information as well as the CIM that need to be taken into consideration when creating CIM-based ESM. These different models/standards and ways of bridging them together comprise the Information layer.

Contextual Layer – This layer formally recognizes that only a subset of the models in the Information Layer are needed for any particular interface or message definition. The Profile standards defined in this layer:

- Define a subset of the models in the Information layer needed for a particular business purpose as well as constraining those model elements to address specific business needs, and
- Provide a way to incorporate model elements from the different information sources in the Information layer in addition to the CIM.

Message Syntax Layer – This layer provides the rules for implementing the Profiles in the Contextual layer in various technologies.

An important feature of this layered architecture is that there are clear boundaries defined between the information models in the Information Layer and the business context in the Contextual Layer. Without this distinction the current CIM has suffered from an “identity crisis” trying to be an information model that also incorporates business context in a non-uniform way. The tension is created by trying to have the CIM be both general enough to be used in any application while being as specifc and constrained as possible to include descriptions more useful to an application in a specific business context.

It’s not possible to satisfy both objectives in an information model, although attempts have been made unknowingly to do just that. This has resulted in an unnecessary “stirring of the CIM pot”, leading to some changes in the CIM information model that could have been avoided. Separating the information model from the business context permits the CIM to stay more general and stable, while permitting new

Profiles to be defined to apply restrictions needed for a specific business context.

Each layer is described in more detail in the following subsections.

2.2. Information Layer

The important architectural features enabled by the layer are described in the following subsections.

2.2.1. Multiple Sources of Information and Metadata

In the current CIM standards, the CIM in UML is the only recognized source of metadata for defining XML messages or files. Although it is possible to extend the CIM with private extensions, and in fact is expected, the goal has been to eventually incorporate those extensions into a later revision of the CIM UML model if the extensions prove to be generally accepted. In any case, the standard CIM UML model with private extensions is the only recognized source for creating a semantic model as the basis for a model-driven architecture.

The Information Layer in the future reference architecture vision, on the other hand, embraces the notion that there are other sources of metadata that a utility enterprise needs to include in its semantic model without trying to make it a part of the CIM standard. Conceptually, some kind of a Bridge, as shown in Figure 1, is needed to create links to these other metadata, similar to the way associations between classes in UML link different parts of the UML model. Whether or not this Bridge becomes the subject of future standards is unclear.

These other information models denoted as Foreign sources in the diagram could include models from other standards bodies or industry consortiums, such as Geography Markup Language (GML). Other possible sources include other TC57 standards, such as the IEC 61850 Substation Automation standards. In fact, this is a very powerful way of achieving harmonization of the 61968/70 CIM-based standards with the 61850 standards. Rather than trying to change these standards to be the same in the Information Layer where there is overlap, the differences can be resolved in the Contextual Layer by making it possible to include attributes from both sets of standards in a Profile, as elaborated more completely in the Contextual Layer section below.

2.2.2. Abstract General Purpose Information Models

Recognizing the Information Layer as separate and distinct from the Contextual Layer has other benefits as well. The CIM can now be thought of as purely an abstract information model that is general enough to be used in a variety of business contexts. So for example, when defining an attribute describing a generator control mode, the CIM can simply provide a string data type. In the Contextual Layer, the string can be replaced with an enumeration that is appropriate for the country where the CIM is being used. This has the advantage of making the generator control mode in the CIM reusable in many different contexts as well as providing a standard way to constrain the permissable values in a particular business context. This has the benefit of providing for the possibility of validity checking of the instance data to ensure only one of the permitted values is used in an information exchange implementation that includes this attribute.

Another problem this addresses is caused by the use of inheritance in the CIM model. Attributes that are inherited from a parent class have only a general purpose name. In the Contextual Layer the name can be changed to include some reference to the specialized class where it is being used, so that in a particular message payload or file in the Implementation Layer, it will be clear what object the attribute applies to.

2.3. Contextual Layer

The Contextual Layer provides for the definition of Profiles to define a subset of the information models contained in the Information Layer that are needed in a specific business context. Business context or constraints are also applied in this layer. This notion embraces many of the concepts described in the UN/CEFACT Core Components Technical Specification (CCTS) (see Reference 1). Profiles may also incorporate the identification of services to be used for information exchange.

2.3.1. Profile as a Subset of the CIM

The notion of Profiles is not new. For example, the CPSM (Common Power System Model) Profile shown in Figure 1 is currently used to define the subset of classes and attributes that are needed to exchange power system models between RTO/ISOs for maintaining network models of neighboring regions. The CPSM Profile is then used to create the message syntax to be used in actual implementations, in this case to define an RDF/XML schema for the generation of CIM-based XML files or messages. This profile has been standardized as draft IEC 61970-452 and is equivalent to a Platform Independent Model (PIM) as defined in the ONG Model Driven Architecture (MDA). An RDF/XML schema implementation of this profile has also been standardized as IEC 61970-501 and draft 61970-552-4.

2.3.2. Profiles and Multiple Information Sources

In the new vision shown in the diagram, the concept of a Profile has been substantially expanded, so that a Profile can apply a business context to a subset of metadata from multiple information models via the Bridge concept. As shown in Figure 1, the Profile object in the Contextual Layer incorporates metadata from the CIM, private extensions to the CIM, and via the Bridge, other information models as well. The key is to maintain traceability back to the source to facilitate long term management and maintenance of the Profiles as new versions of the information model standards are published.

2.3.3. PIMs and PSMs

Another important concept embodied in the Profiles is the notion that they represent a Platform Independent Model (PIM) of an information exchange or interface, thus creating a clear boundary between the Contextual Layer and the Implementation Layer, where there may be multiple technology implementations of that profile. The standards in the Implementation Layer then are the Platform Specific Models (PSMs). So it can be seen that the future TC57 layered architecture embraces the MDA concepts of PIMs and PSMs.

In Figure 1, the Common Profile object as shown can be implemented in several technologies, each with its own syntax, including RDF/XML schema, XML schema, and a relational database schema. This implies that a Profile must be specified at a high enough level of abstraction to allow it to be implemented in various, different technologies.

2.4. Message Syntax Layer

This layer includes standards for concrete implementations of information exchanges and interfaces to the level of specificity required for achieving interoperability between products/applications/systems from different suppliers. These standards also form the basis for compliance testing to validate system interfaces. As such, they must be technology specific.

Since these PSM standards are based on the PIMs in the Contextual Layer, it is important that they include clear rules for how they are derived from the PIMs. For example, there are several XML Schema structures that can be generated from a single Profile definition – each one correct but different, and not interoperable. So it is important that the PSM standards also include rules for creating the PSM from the PIM. For example, as shown in Figure 1, three different PSMs may be derived from the Common Profile. Each has a different set of rules that must be defined. For generating CIM/XML files based on RDF Schema, rules are defined by WG13 to define the subset of and extensions to the RDF Schema elements as defined by W3C to be used. These are incorporated in a standard so that there is one accepted way of using RDF schema to create the file metadata. Similarly, for the XML Schemas defined by WG14 for message exchange between distribution systems, a set of rules is needed to define how the XML schemas are to be derived from the common profile. As a last example, a project may define a new technology mapping to a relational database with its own set of rules outside the standards arena.

2.5. Concrete Messages and the Three Layer Architecture

Figure 2 illustrates how this three-layered architecture all fits together to define a concrete message for information exchange based on the CIM. Note that this illustration shows only the CIM as a source of the information metadata, but the concepts apply regardless of the information source.

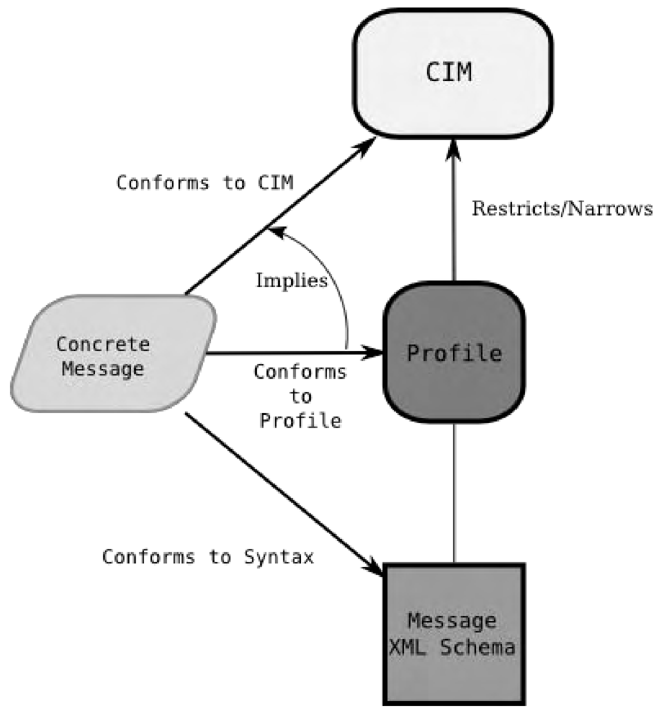

Figure 2, Concrete Message Generation

The CIM is shown as the source of the information metadata used in the message. The Profile defines the subset of the CIM that is to be used in the message, thus restricting the CIM to only those parts needed for the particular business process and information exchange in view. It also adds business context to that subset of the CIM to take the CIM from a general purpose application-independent information model to a semantic model that better represents the specific business context and is thus application-dependent. However, at this point the Profile is still abstract (i.e., technology neutral). The Message XML Schema is then generated from the Profile and CIM following the standard rules for mapping to XML Schema, when the desired concrete message is to be an XML document.

As may be seen in the diagram, the concrete message needs to conform to the CIM standards at three points:

1. The CIM for the information metadata
2. The Profile for the business context restrictions
3. The Message XML Schema for the message syntax

With this view of conformance in view, compliance testing can be better understood. This is an area that is currently not well defined from an architectural perspective, i.e., how to test for compliance with CIM standards, or even more basic, what is the meaning of compliance with CIM standards. Figure 2 illustrates where compliance is necessary to achieve interoperability and claim "compliance with the CIM."

2.6. Service Model and Interfaces

Interoperability is really about interfaces. An important part of an interface are the services used to exchange information with other systems. SOA and Web services provide a robust services environment but are independent of content. Underlying the reference architecture discussed above are another part of the CIM related standards known as the Generic Interface Definition (GID) services that are part of the IEC 61970 series of standards. The GID includes CIM-aware standards for access to complex data structures, for high speed data exchange, for historical data access, for publishing and subscribing. CIM-aware means data can be browsed and accessed based the CIM representation of the data in view. When combined with specific concrete message payloads based on the CIM, they define an interface that can be tested for interoperability and standards compliance.

3. CONCLUSION

The authors believe that the concepts and supporting standards presented represent the next logical step in the evolution of the CIM standards to help achieve interoperability between the variety of systems used by electric utility transmission and distribution. However, the concepts presented apply equally well to a variety of other domains of application within the scope of the GridWise Architecture framework.

4. REFERENCES AND ACKNOWLEDGEMENTS

Key concepts for this paper were based on working drafts developed in IEC TC57. In particular, the authors want to acknowledge the contributions of Jean-Luc Sanson (EDF), Xiaofeng Wang (Xtensible Solutions), and Arnold deVos (Langdale Consulting). The layered reference architecture described in this paper is also loosely based on concepts described in the following references.

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Biography

David Becker is the Manager of Control Center Technologies, Electric Power Research Institute (EPRI) in Palo Alto, California. He is responsible for formulating research strategies for power system control centers. Mr. Becker's current projects include implementation of new technologies incorporating standards, system concepts, and competitive designs to provide solutions for the electric system. Mr. Becker has spent over 15 years guiding the development the CIM, which is now an international standard IEC 61970. Mr. Becker also was sponsor for development of the IEC 60870 Inter-Control Center Communications Protocol (ICCP) and a short- term load forecaster called EPRI ANNSTLF. This forecaster is widely used in the U.S. and abroad. Before joining EPRI in 1993, Mr. Becker worked for Pacific Gas and Electric Company (PG&E) in various operational and managerial roles. He is a Senior Member of IEEE, a USA delegate to IEC TC57 WG13, which is responsible for the CIM standards, and is active in numerous task forces and working groups related to system operations and control centers. Mr. Becker holds a BSEE from Lafayette College in Easton, Pennsylvania, and an MS Engineering Management from the University of Santa Clara, in Santa Clara, California.

Terry Saxton is Vice President and a founder of Xtensible Solutions, a company offering professional consulting services to the international utility industry in the development of Enterprise Information Management (EIM) strategies and frameworks based on the Common Information Model (CIM) and related standards. Mr. Saxton is Convener of IEC TC57 WG13 responsible for the CIM and other international standards for energy management system interfaces. He manages projects for EPRI dealing with the CIM, most recently extending the CIM to support planning applications. Mr. Saxton has many years of experience in the analysis, design, development, and implementation of a wide range of system integration solutions for electric utilities and the US Department of Defense. Prior to starting Xtensible Solutions, Mr. Saxton worked for BearingPoint, KEMA Consulting, Siemens Power Systems Control, Honeywell, Information Exchange Systems, and Bell Telephone Laboratories. He received an MSEE from the Massachusetts Institute of Technology (MIT) in Cambridge, Massachusetts, USA, and BSEE and BS Math with Honors from California State Polytechnic University.

The DSR Potential of University of New Mexico's District Energy System

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Abstract

Eighty-six of the University of New Mexico's (UNM) main campus buildings are serviced by a district energy system which receives electricity and natural gas from the local utility company. UNM's Physical Plant Department recently installed a metering, monitoring and verification (MMV) system which collects information about campus energy use. The MMV was designed with several features which allow for future interoperability with other building system services such as DDC, industrial controllers, security, and fire alarm systems. The design includes programmable logic controllers (PLC's) that communicate using MODBUS, native BACnet, BACnet IP, security and fire alarm protocols on the building side and MODBUS IP and BACNET IP on the network side. Furthermore, one building (Mechanical Engineering) is being instrumented to collect information about the energy use of individual systems within the building (fans, pumps, chillers etc.). The building has thermal storage tanks and a solar assisted heating and cooling system, which allow substantial flexibility in the building energy consumption profile, and a digital control (DDC) system which allows for automated decision making based on inputs from external IT systems. We analyze the electrical energy usage of campus for the purpose of estimating the potential of the UNM campus to respond to grid status information, by altering its energy consumption characteristics. Possible response (reactive and predictive) strategies are discussed in light of inputs from various IT systems, such as scheduling databases, weather forecasts, utility data. We estimate a potential 3 MW response, with more if several IT and physical systems are put in place.

1. INTRODUCTION

The vision of interoperability outlined by the GridWise Architecture Council's 2005 white papers [1,2] enables the integration of diverse participating subsystems in a larger system which can operate optimally, while freeing the medium- and long-term evolution of the system from *a priori* decisions which may become superseded and counterproductive in the future.

In 2001, UNM began a utility infrastructure investment program intended to reduce the use of energy associated with campus lighting, heating and cooling. The core of the investment was the renovation of the Ford Utilities Center, including the installation of a 6 MW co-generation turbine, boilers, and chillers, serving a 650 acre campus inhabited by over 25,000 people. The co-generation plant is currently operated when it is cheaper to produce electricity than to buy it (also accounting for heat recovery). The co-generation plant currently meets ~40% of the campus electricity needs and 65% of the heating needs (in terms of total energy). A new Energy Management and Control System (EMCS) was installed in the renovation, with the capability of monitoring and controlling energy use on campus from a remote location. Currently, the EMCS operates as a Metering, Monitoring and Verification (MMV) system, with no control function, with meters located at the boundary of each building.

Refurbishment and modernization of the Mechanical Engineering (ME) building began in 2006. The ME building is characterized by load-dominated high-thermal mass construction, by the capacity for thermal storage and by solar-assisted heating and cooling. For this building, monitoring is implemented on a finer scale, allowing for external intervention on the operation of individual systems. This building is viewed as a prototype of a grid-cooperative building of the future, and its potential will be compared to that of more conventional buildings on campus.

Because of these features, the University of New Mexico's central campus was identified as an ideal example on which to base a demonstration of interoperability concepts. While electricity consumption and production on UNM campus is currently managed based on real-time internal needs for lighting, cooling and heating, with the only external consideration being gas and electricity prices, we envision a future where interaction with the grid is bi-directional and real-time. In this study we analyze the overall electricity consumption patterns of the UNM central campus, and of a set of individual buildings therein in more detail. The possibility of altering the electricity use and production patterns based on external requests from the grid is investigated, while ensuring conditions necessary for fulfilling UNM's academic mission. As a consequence, it is necessary for the EMCS to interrogate other relevant IT systems, such as scheduling, security and weather services. We also consider the possibility of automatically responding to information such as curtailment signals, price signals, or energy "quality" signals (e.g. intermittent renewable resources such as the wind farm near Fort Sumner, New Mexico).

2. SUMMER ELECTRICITY CONSUMPTION

Summer is the period of highest grid stress. The peak loads reported by the Public Service Company of New Mexico (PNM) in the period studied of July to September 2006 coincided exactly with the highest temperatures. Because grid interoperability should be pro-active rather than just reactive, and because the response time of many grid operators (e.g. buildings) can be measured in hours, a predictive ability which can extend from one to a few days is valuable. In the response strategies discussed later, the ability to forecast the probability of curtailment requests will be assumed.

2.1. Campus electricity consumption patterns

UNM purchases electricity from PNM at rates described in the Advice Notice No. 318 [3]. The metered electricity consumption rate for August of 2006 is shown in Fig 1. Weekday consumption is approximately 4 MW higher than on weekends. The sharp spikes in purchased power visible on weekday mornings are due to building startup after nightly and weekend system shut-off. The downward part of the spike is a consequence of achievement of setpoints in the buildings and the start-up of the co-generation plant. The demand spike is higher on Mondays, as a consequence of building conditions having fallen further away from the setpoint during the weekend. The on-peak period is 8:00AM to 8:00PM on weekdays. The energy rate for on-peak operation is $0.046/kWh, with an on-peak demand charge of $7.022/kW for demand above 8,000kW. Off-peak, the energy charge is $0.026/kWh. The monthly customer charge is the on-peak period demand charge applied to the 8,000 kW minimum demand. Thus, the rate of purchased energy is maintained above 8,000 kW and rarely falls below this value.

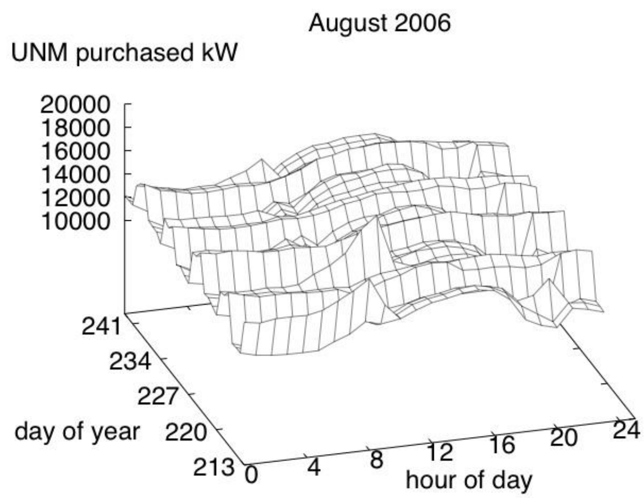

Figure 1: Metered electricity purchased by UNM central and North campusin August 2006.

2.2. Co-generation plant operation

The operation of the co-generation plant for the week containing the PNM peak load in August is shown in Fig. 2. The plant can achieve full power (6 MW) in less than 30 minutes. The overall cycle efficiency for the co-generation plant is on the order of 70%. Moreover, the combustion of natural gas results in lower greenhouse gas emissions relative to coal. Thus, from a thermodynamic and environmental point of view, there is considerable advantage in producing electricity locally, however now economic considerations only decide plant operation.

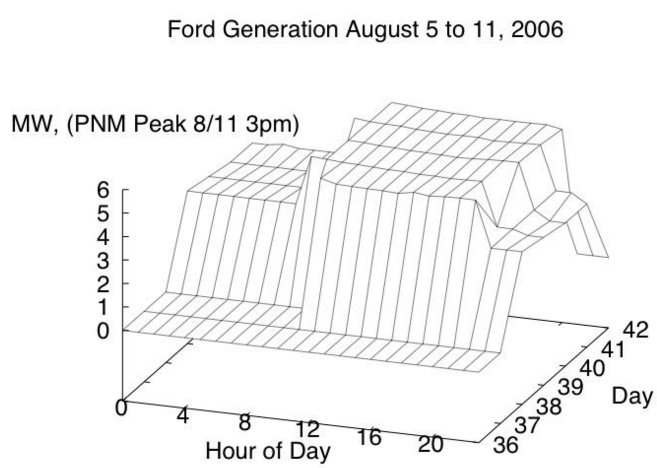

Figure 2: Electricity generation at the UNM Ford Utilities plant for the week of August 5-11, 2006.

The pattern of operation is similar for all summer weeks. The generator is shut off on weekends. During weekdays, it operates between 3 MW and 4 MW until 8 AM, when it is ramped to approximately 6 MW. The power is reduced to 3-4 MW again after 8 PM. This pattern leaves little opportunity for using the generator for campus load shedding during peak hours, when the turbine is already operating at peak capacity. It could be used in conjunction with other strategies, for example for pre-cooling of buildings off-peak, however doing so would be economically detrimental with current rate structures, as purchased electricity off-peak is cheaper than locally generated electricity, even accounting for added efficiencies resulting from heat recovery. Factors other than economics may be taken into account if this or additional co-genration plant is to take part in real-time energy markets.

3. BUILDING-WISE CONSUMPTION PATTERNS

The UNM central and north campus is the object of this study, as it is monitored and can potentially be controlled by the central EMCS. In 2001, there were a total of 231 buildings, with a collective surface area of 590,536 m^2. A subset of these buildings (86) are connected to the District Energy System and 65 are metered through the ECMS, and constitute 70% of the total building area. For this study, 5 representative buildings, representing a cross-section of building type, mechanical equipment and end-use, and collectively constituting ~10% of the total DES-served space, are considered. These buildings will be utilized to determine the curtailment strategies that may be implemented. Based on the results, the response characteristics of the entire campus will be extrapolated.

3.1. Mechanical Engineering

The Mechanical Engineering (ME) building is composed of research laboratories, classrooms, and offices and contains 6530 m^2 gross floor space. It has 6 supply fans and 2 return fans totaling 122 kW. The building is heated by the campus steam system with additional heat supplied by a roof mounted solar thermal system. The cooling coils draw chilled water (CHW) from thermal storage tanks, supplemented by an absorption chiller operating from the solar heating system. The storage tanks are recharged using a heat exchanger connected to campus chilled water.

The Mechanical Engineering building in the first week of semester in 2006 displayed an electric load varying from 150 kW to 250 kW during weekdays (Fig. 3). The added load, compared to weekends is caused by lights, computers and occupants (approximately 75 faculty, staff and graduate students, and up to 200 students attending class). The energy consumption for this building in 2006 matched the average campus consumption per unit area. In 2006, a four-stage electric chiller consuming up to 100 kW was used to meet the thermal load as required. In addition, fans consuming about 100 kW were constantly in operation. The restoration of the thermal storage tanks, the addition of the solar water-fired absorption chiller, and the installation of fan speed controls will return the energy consumption to its 1981 pattern (Fig. 4).

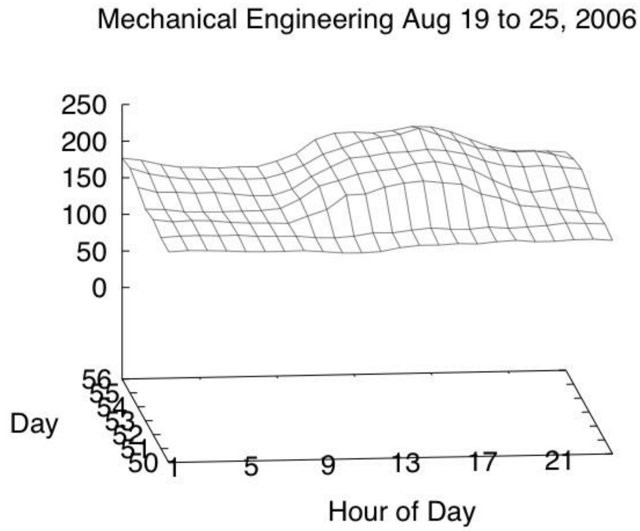

Figure 3: Electrical load for ME building in August 2006.

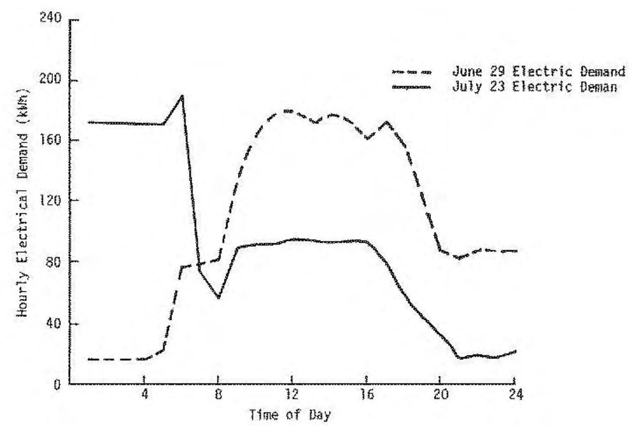

Figure 4: Measured electricity consumption for the ME building with thermal storage (July) and without thermal storage (June) in 1981.

With the new fan controls, we estimate the ability to run the ME building at approximately 100 kW at peak, and to reduce the load to approximately 70 kW following a curtailment request. Using the monitoring system, including flow meters and temperature sensors at appropriate locations in the hot and cold water storage system, the solar system and the heat exchanger interfacing ME with Ford DES, we will be able to experiment with various load shedding strategies, and measure the response in real time. We will also determine whether the additional level of information allows a greater degree of interoperability in comparison with other buildings where energy use is only monitored at the building boundary.

3.2. Electrical, Electronic and Computer Engineering

The Electrical, Electronic, and Computer Engineering (EECE) building is composed of research laboratories, classrooms, offices, and the Centennial Engineering Library (16,630 m^2 of gross floor space). The 9 air handling units contain 9 supply fans and 3 return fans totaling 201 kW. The three largest air handling units have variable frequency drives (VFD) for their fans (146 kW). The air handling units include dual and single duct systems. Cooling is supplied by the campus chilled water system.

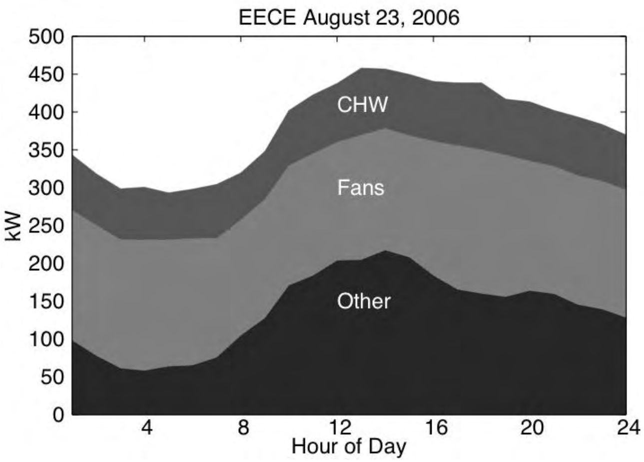

Figure 5: Total electricity usage (metered and CHW) for the EECE building on August 23. Note the large baseload due to the constant operation of fans which however could be set back if space sensors were installed.

The EECE building experiences a metered base load of approximately 200 kW, increasing to a peak of 375 kW which extends through the afternoon (Fig. 5). The baseload is due largely to fans that are not set back or shut down due to lack of space sensors. There is little difference between operation with and without students. The small effect of student occupancy is not surprising, due to the small fraction of the building dedicated to classrooms. It is difficult to account for the effect of library occupancy, as data are not available. However the library entry and exit gates could be used to log statistics and real-time data.

For this building, we estimate a load shedding capability of 50kW for chilled water and 50kW for fans, with current capabilities or small additions (space sensors informing the DDC).

3.3. Dane Smith Hall

Dane Smith Hall is composed of classrooms and contains 9084 m^2 of gross floor space with six air handling units. These air handling units contain six supply fans totaling 93 kW, each with VFD speed control. Each system is single duct with heating from the campus steam and cooling fromcampus chilled water. The electricity consumption is typical for a load-dominated building, in which the principal load is due to student occupancy, and where setpoints are raised at night. There is a metered baseload of about 70 kW, with an afternoon peak of about 175 kW. Student occupancy data reconstructed from the scheduling database (Fig. 6) show a daily student count between 800 and 1600 for the period 8 AM to 4 PM, and a secondary peak from 5 PM to 8 PM corresponding to evening classes.

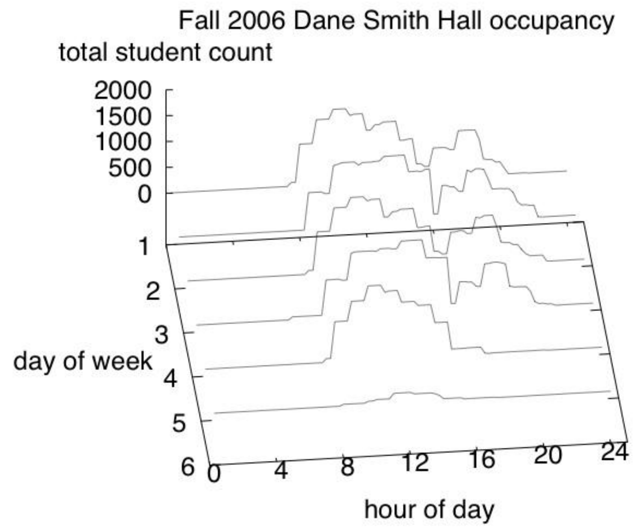

Figure 6: Reconstruction of student occupancy for the Fall 2006 semester, from scheduling database.

The break-up of energy consumption (Fig. 7) for a typical day in late August shows no CHW or fan load at night. During the day these become significant, closely following the shape of the occupancy. Overall, this building offers substantial flexibility but also requires a high level of systems interoperability (scheduling, occupancy sensors, lighting controls) for complete optimization.

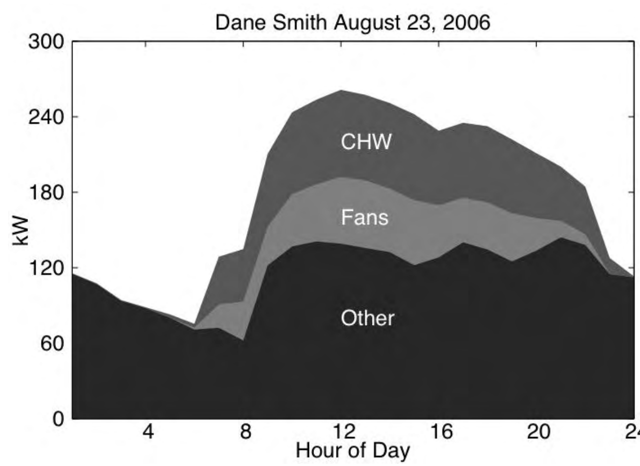

Figure 7: Break-up of electricity consumption for Dane Smith Hall on August 23, 2006.

With current capability, we estimate a load shedding capacity of 70 kW with minimal loss of comfort. More aggressive automated load shedding could take place if the scheduling database could be queried for current and predicted occupancy.

3.4. Cancer Research Facility

The Cancer Research Facility is composed of research laboratories and offices and contains 7592 m^2 of gross floor space with three air handling units. The main air handling units contain 4 supply fans and 4 exhaust fans with a total fan capacity of 298 kW. The facility is a significant energy user in that it uses 100% outside air. The facility contains 4 biohazard laboratories with a dedicated exhaust fan each and a common standby exhaust fan with a total capacity of 15 kW. The main exhaust fans have VFD speed control and the supply fans have econo disk speed controls. The system operates continuously. The air handling units are single duct with heating from the campus steam system and cooling from campus chilled water system. We estimate a combined load shedding capacity of 150 kW for this building.

3.5. Fine Arts Center and Popejoy Hall

The Fine Arts Center and Popejoy Hall operate on a common set of controls and contain 22,940 m^2 of gross floor space with 13 separate air handling units. The facility contains classrooms, offices, practice studios, and a large public performance hall. The air handling units contain 17 fans totaling 220 kW. None of the fans have speed control equipment. The air handling units include dual and single duct systems. With the exception of one system, heating is from campus steam and cooling is from campus chilled water. The Popejoy backstage system is a package unit with natural gas for heat and an electric A/C compressor.

The complex displays a fairly flat energy consumption profile, varying from 250 kW to 300 kW. The scope for load reduction is limited. An increase in the temperature setpoint would produce a reduction in the flow rate of chilled water, but no decrease in fan speed. A few large air handling units (Popejoy, Keller, Rodey) could be shut off completely if no performances or rehearsals were scheduled. This should be done automatically, regardless of grid-related curtailment requests, based on information from the scheduling database. Careful consideration should be given to ensuring that thermal inertia of the building is accounted for and that the cooling system is capable of absorbing the load from eventual large audiences in the performance spaces as well as the load related to cooling the building structure. The electric load is dominated by lighting and equipment, a substantial amount of fan power, and a relatively small electric load required for CHW production. The relatively small CHW-related electric load is due to the extremely efficient chillers in the UNM District Energy System. We estimate a curtailment capacity of 85 kW for the complex.

4. BUILDING-LEVEL CURTAILMENT

We consider the following curtailment strategies, in order of preference:

1. Curtail HVAC for non-occupied areas. This is best done in coordination with scheduling information, both taking advantage of `thermal inertia' and avoiding discomfort caused by it. Also, scheduling software should take HVAC zones into consideration.
2. Raise cooling set point by specified amounts, depending on level of curtailment required. This can only be done where DDC controls are available down to the individual zone, such as in Dane Smith Hall. Where zone controls are antiquated or otherwise non-existent, some curtailment may be achievable by adjusting the AHU supply air temperature setpoint, but the balance between fan energy and CHW energy will need to be carefully monitored to see any savings.
3. Reduce VFD control on fans by a set amount, which could be related to curtailment request. This is simple to accomplish for some of the buildings in this study by lowering the duct static pressure requirement which will cause the VFDs to slow. Pre-cooling may take place during off-peak hours or before likely curtailment requests.

To obtain a quantitative measure of the effect of strategies (2) and (3), a building similar to Dane Smith Hall was simulated in a building simulation code (TRNSYS 16). In particular, a section of the building was modeled in detail, including a fan and a cooling coil. The supply air to the fan is a mixture of return and outside air, which can be varied to ensure that adequate fresh air is supplied for low fan speeds.

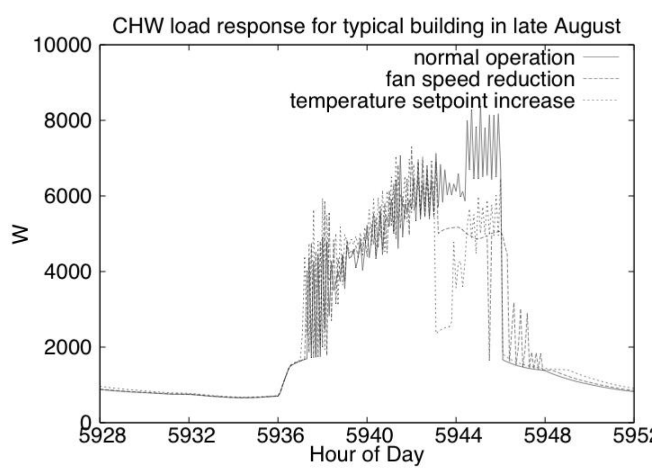

Figure 8: Electric load due to production of chilled water for an 875 m^2 section of a classroom building, under various curtailment strategies. Curtailment signal at hour 5943.

When the temperature set point is increased by 2°C, following a hypothetical curtailment request, a fast increase in temperature to the new set point results. The power required to produce chilled water initially drops sharply (Fig. 8) then begin to rise after 1hour, to reduced levels. The fan power behaves similarly. If direct control over the fan VFDs is possible, then the maximum speed can be re-set. In the simulation, the maximum fan speed was set to 1/3 of its normal maximum value. The result is a gradual increase in temperature which may be less perceptible to the occupants than a sudden one. The chilled water power is reduced to a level moderately below the normal (Fig. 8) while the fan power remains constant at approximately 1/4 of the "no-curtailment" level (Fig. 9). This strategy would be most suitable in conjunction with thermal storage, as in the case of the Mechanical Engineering building, or where the thermal inertia of chilled water system is large enough that central chilled water production can be curtailed independently of the actions taken in individual buildings.

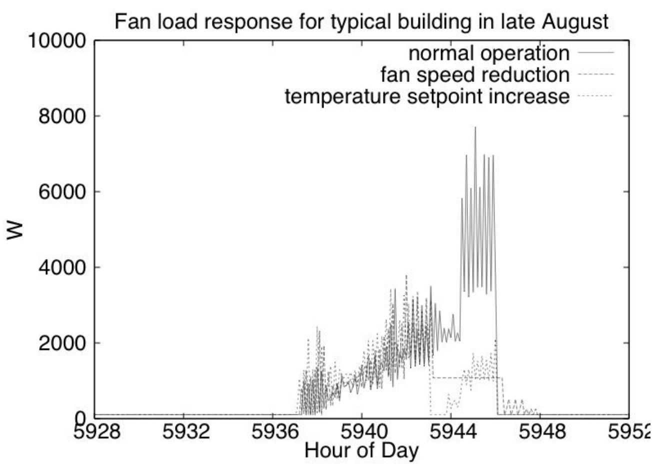

Figure 9: Fan electric load for a classroom building, under various curtailment strategies. Curtailment at hour 5943.

For both cases, the time-averaged response to a curtailment request is approximately 7.5 W/m^2, without significantly affecting comfort levels. If these response levels are taken to be representative of the average over all buildings on campus, then a total response of 3MW is possible. This level of response is achievable currently. However, increasing the use of information available could enable more aggressive curtailment, without the need for substantial capital investments. For example, if interrogation of the scheduling database reveals very low occupancy levels for a particular building for a period of several hours (e.g. Dane Smith Hall on a Friday, Fig. 6), then chilled water to the building could be cut completely. Weather forecasts, indicating the likelihood of curtailment requests, could also be used for this purpose. The structure of the building could be pre-cooled overnight, at low cost and efficiently due to the favorable thermodynamic conditions.

BACnet web-enabled control systems such as Delta allow inputs to be made realtime to adjust setpoints or change to operational strategies. Older control systems such as Inet can take an external input but it must be applied to the entire building (e.g., night or curtailment mode) due to bandwidth limitations in the systems routers. In most cases, DDC control systems are configurable with curtailment options, but they have not been used to date at UNM.

5. CONCLUSIONS AND RECOMMENDATIONS

There is a ~3MW curtailment potential with existing infrastructure, more if IT systems are fully integrated with ECMS or the energy portal. We recommend that discussions begin with UNM student representatives, faculty and staff to determine possible incentives (eg. partial refund of student fees from energy curtailment savings etc). PNM should propose incentive scheme for UNM. Physical infrastructure is necessary for full interoperability. A second turbine will be used to generate at peak. Capital improvement are necessary to allow these and additional strategies to be implemented. In order of technical preference, these are:

1. Zone-level DDC installed in concert with both lighting controls and fan VFDs to allow each space's entire energy usage to be modulated in response to load, occupancy and grid needs.
2. Photovoltaics in roofing systems to supplement the central cogeneration capabilities. While this cannot strictly be classified as curtailment, it would enable greater flexibility in the allocation of the co-generation resource, given that peak electricity production would generally coincide with peak use.
3. Central thermal storage may be feasible when City of Albuquerque abandons the 32,000 m^3 Yale reservoir. If used to store chilled water, it could satisfy campus CHW requirements for several hours daily, releasing approximately 2 MW of production capacity currently dedicated to operating the central CHW production. Furthermore, it could be used to absorb off-peak wind generated electricity.

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Author biographies

Andrea Mammoli obtained his Ph.D. in Mechanical Engineering at the University of Western Australia in 1995. He was a Postdoctoral Fellow at Los Alamos National Laboratory until 1997, when he joined the faculty of the Mechanical Engineering Department at the University of New Mexico. Prof. Mammoli's research interests are in computational mechanics, materials, and thermofluids. Since a sabbatical in Italy in 2004, he became interested in all aspects of building energy use, from passive solar design to high-tech solutions. He is currently PI on a project dealing with the restoration and modernization of UNM's mechanical engineering building thermal solar and storage system, on the UNM GridWise demonstration project, and on the development of utility-scale collectors for thermoelectric generation. Prof. Mammoli has authored or co-authored over 40 peer reviewed articles and conference proceedings.

Don Lincoln is currently a PhD candidate in Mechanical Engineering at the University of New Mexico. He also functions as a consultant to the Facilities Management and Operations Center at Sandia National Laboratories. He has over 30 years of experience in the electric power generation engineering and maintenance fields. He was recently the Director of Commercial Utility Programs, for Alion Science and Technology (the former Illinois Institute of Technology's Research Institute). In that position he managed a process analysis group and developed a hydraulics test laboratory supporting the nuclear industry's pressurized water reactor (PWR) containment sump issue. With Alion, he managed international consulting projects in the Ukraine, Canada, France, Spain, and Japan. Mr. Lincoln holds a B.S. and M.S. in Mechanical Engineering from the University of Nebraska and is a registered professional engineer.

Hans Barsun is a facilities engineer with the UNM Physical Plant Department in the Engineering & Energy Services Division. One of his primary duties is to monitor the energy usage in buildings on the UNM campus and to identify opportunities for increased efficiency. He also is responsible for design oversight on new capital projects at the university and managing mechanical and energy conservation projects. One of the most interesting projects that he is involved with is the Gridwise Demonstration / Solar Revival project at the UNM's Mechanical Engineering building, which is updating an old solar thermal system installed in 1980. Prior to joining UNM, he spent 10 years as a facilities engineer at Intel where he worked with the cleanroom air handling systems along with exhaust and liquid waste treatment systems. He earned a Masters degree from UNM and earlier graduated from Purdue with a degree in Aeronautical Engineering.

Larry Schuster is currently the University of New Mexico Utilities Engineer. He manages the operation of the UNM energy management data system described in the paper. He was previously assigned to assist the C.E.O. of the University of New Mexico subsidiary charged with development of a utilities renovation project business plan and, during execution of the business plan, he was the Project Manager for all the Chilled Water System Improvement Projects and Director of the Utility Project Team responsible for the entire project. The data system was one component of the plan improvements. He has earned BSME and MSME degrees from the University of New Mexico, is an Association of Energy Engineers Certified Energy Manager and Green Building Engineer, and licensed professional engineer. He has taught in the UNM School of Architecture and Planning for 18 years, currently teaches in the UNM Mechanical Engineering Department, and has worked at the University of New Mexico for over 30 years in various capacities.

Mario Ortiz obtained his BS in Mechanical Engineering with an economics minor from New Mexico State University in 1998. He gained experience in the manufacturing environment through co-ops with Ethicon Endo Surgery in Albuquerque, New Mexico and Ethicon in San Angelo, Texas. He worked on waste measurement systems for BNFL Instruments in Los Alamos, New Mexico from 1998 to 1999. Worked on semiconductor process metrology systems for Bio-Rad in Albuquerque, New Mexico from 1999-2003. In 2003 he began pursuing a masters degree in ME and a career in the sustainable energy field at the University of New Mexico in Albuquerque, New Mexico.

Jack Mc Gowan is President & CEO of Energy Control Inc. (ECI), an Energy Service Company and System Integrator. ECI has been on the Flying 40 list of fastest growing technology companies in New Mexico for the past five years, and also won the Association of Commerce and Industry Viva Award in 2004 for Vision, Investment, Vitality and Action. SDM Magazine named ECI among the Top 100 System Integrators in North America for the past five years. Mc Gowan is Chairman of the U.S. Department of Energy GridWise Architecture Council. He is an author and has published 5 books including "Direct Digital Control" on Fairmont Press and over 125 articles. Mc Gowan was chosen by his peers as 2006 Visionary at the Builconn Intelligent Buildings and GridWise Expo. The Association of Energy Engineers admitted him to the "International Energy Managers Hall of Fame" in 2003 and named him "International Energy Professional of the Year" in 1997. He also sits on the Energy and Power Management Technical Advisory Board and is a Contributing Editor with WWW.Automatedbuildings.com, Engineered Systems and CABA's Intelligent Homes and Buildings.

A Three Case Study Comparison: Creating a Marketplace for Implementation Ready Interoperable Products

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Keywords: COTS, Interoperable, Community, RFC4130, RFC3335, RosettaNet

Abstract

The article shows the different outcomes of interoperability certification programs instituted for three well known industry standards; why some became heavily used and others did not even though all three standards were well designed to address business needs.

1. ACHIEVING INTEROPERBILITY IS DIFFICULT

Defining Information Technology (IT) interoperability and the roadmap to achieving this goal remains a difficult endeavor as it varies with the industry, the technology and the final purpose under discussion. Basic interoperability can be defined as two or more IT systems intercommunicating with security, timeliness, and compliance to their designed purpose. This usually comes down to the execution of a common business or technical process among the interoperable systems with adherence to the stated goal of the process. However, the techniques on how that 'interoperability' is accomplished among different commercial software products are where the misinterpretation or confusion lies.

The United States Government has been buying, promoting and using the phrase 'Commercial Off the Shelf (COTS) products for the past twenty years to reduce the associated implementation, integration and support cost in IT projects with great success.

If we are talking about interoperability across internet/supply chains then the only definition that makes sense is a community of COTS Interoperable products. Note that the word interoperable has no real usefulness without 'COTS' or 'community' in the context of wide scale implementation. All three are necessary to accomplish the goal – the goal of providing the end-user community of software purchasers with a set of known products that are COTS interoperable among themselves that may be installed and will intercommunicate in an interoperable manner with little or reduced requirements for costly professional services to implement.

There are many nuances on how to accomplish a community of COTS interoperable products depending on technologies under test, the target market place for the products, the end network configurations the products must operate within and whether the market place is composed of early or late adopters. Since all of these factors cannot be dissected here, I'll focus on three case studies of attempts to develop a community of COTS interoperable products. One of these is very successful, one of these is partially successful and one has not lived up to its potential. The different outcomes have less to do with the technical details of the standard, but rather on the test methodology, test environment and the degree to which the end-user community chose to support the certification programs.

2. THE THREE STANDARDS

The three standards are RFC4130, RFC3335, and the set of RosettaNet standards.

1. Very Successful: RFC4130 is a secure, reliable messaging standard based on HTTP which is heavily used across the world in a variety of industries including retail and financial services.

2. Partially Successful: RFC3335 is a secure reliable messaging standard based on SMTP which is less used, across the world primarily in retail.

3. Not Met Potential: RosettaNet standards have two components secure messaging and document. The standard is used in the Pacific Rim and the USA in the computer and consumer electronic industries.

3. FACTORS FOR SUCCESS

Although there are many differences in the above three cases of how the interoperable products were developed, there are three major factors which I strongly believe, having been involved with each of these, determined the degree of success:

3.1. The Techniques

The techniques used to achieve the technical 'interoperability' between the products

There are various techniques for achieving technical interoperability depending on whether one is dealing with communications technologies, syntax, semantics, or business process standards to name a few. However, regardless of which of the above one is dealing with, the two most common methods are:

- The conformance engine technique – one-to-many testing.
- The other is the full matrix interoperability technique – all-to-all testing.

3.2. The Testing Environment

The testing environment and setting for the interoperability tests.

Interoperability provides little benefit to the end-user community if it only works in a laboratory test environment, which I'll refer to as 'product interoperability'. It also must translate into interoperability in the production/ real life environment in order to provide a major cost saving to the end-user companies – ROI, of course being the key driver.

3.3. End-user Support

The degree of support and adoption of COT interoperable products by the end user community is critical.

Undergoing software certification testing requires an investment of both time and money from the software vendor. Unless there is unified industry support among end-users to only purchase certified software products, there is little incentive for software companies to invest the time and money for interoperability certification testing.

4. STANDARDS SUCCESS ANALYSIS

RFC4130 (AS2):

1) was tested in a full matrix interoperable test environment – all products to all products,
2) the test was not conducted in a laboratory, but over the live Internet simulating the a live implementation environment and finally
3) a major group of end users committed to only using certified interoperable products. These three things developed a highly success full set of over 50 COTS products that were implementation ready, that is 'a community of COTS interoperable products'.

Users report that they can install products and start communicating within a few hours if certified products are used versus days or weeks when using non-certified products. This saved the industry tens of millions of dollars by avoiding the need for professional services.

The end result was:

- Reduced the cost to operate
- Reduced capital IT cost
- Reduced installation cost
- Reduced upgrade cost
- Better security management
- More choice in products
- More price points & features

RFC3335 (AS1):

1) was tested in a full matrix interoperable test environment – all products to all products,
2) over Internet to simulate a live production environment, but
3) did not have a group of users commit to implementing only interoperable certified products in their supply chains.

These products install as easily and quickly as above **RFC4130 (AS2**); however there are a little more than 10 of these products offerings world wide. A community of COTS products developed, but a successful marketplace did not and hence little ongoing investment by the software community for implementing additional bells-and-whistles.

The set of RosettaNet Standards:

1) used the conformance engine technique – one-to-many testing
2) they were tested over internet but in a partially sequestered test lab environment and finally
3) no set of end-users committed to using only certified products in their supply chains.

These products are time consuming to install at the messaging level. Since the conformance engine had bugs requiring ongoing fixes, that meant that Product A may have tested against a different code base version of the reference product than Product B. In a one to many testing scenario, if the reference or conformance engine code base is changing on an ongoing basis, then interoperability becomes an elusive, constantly moving target.

RosettaNet has expanded messaging options by adding RFC4130 and ebXML which will greatly enhance the message level COTS. However this will not solve the ongoing problems associated with the document types that are still tested in a one to many manner. This is a nice standard which did not live up to its potential because the wrong means of technical testing was chosen and no end-users committed to using only certified products in their supply chains.

5. CONCLUSION

The lessons learned from above are straight forward:

1) Interoperability testing should reflect the production environment of the products. A

laboratory environment will often not identify all the real world issues.

2) Conformance testing does not imply interoperability and should be thought of as a pre-stage event to prepare for full product-to-product testing. And finally
3) the production of a community of COTS interoperable products, that is implementation ready products, is much more than a technical effort. It requires a marketing and business plan to educate the market on the value of certified products and the endorsement and support of the end-user community to support the purchase of certified COTS interoperable products.

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Biography

Rik Drummond is the CEO and Chief Scientist of Drummond Group Inc, a global leader in interoperability software certification. With over 20 years of experience in the world of technical standards and eBusiness communication, he is responsible for leading the technical testing strategy and business development for the organization. His experience in working with industry groups, standards groups and hundreds of software vendors from around the world, in testing and certifying software interoperability offers unique insights into “what it really means” to be interoperable. He has worked as a consultant in a wide range of industries: Pharmaceutical, Retail, Consumer Packaged Goods, Automotive, Banking & Financial, Government, Petroleum and Energy.

Drummond was chair of GridWise Architectural Council 2005-2006. He has been involved in the development of XML, EDI, EDI over the Internet (EDI-INT) and electronic messaging. Most recently, he served as the chairperson for an IETF workgroup with more than 400 members - "Secure EDI over the Internet that developed three RFCs 3335, 4130, and 4823, and led the Work Group for the ebXML messaging standard Version 1, an initiative organized through the UN/CEFACT and OASIS. He also served as editor and secretary for the UN/CEFACT Technologies and Methodologies Work Group for UMM, and is involved as a team participant on the UN/CEFACT BFSS.

Business Innovation and Service Abstractions

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Keywords: Innovation, Service Orientation, Security, Abstraction

Abstract

True Scalability and interoperability require abstraction and security. Most control systems today expose name/value tag pairs as their interface. Interaction with exposed tag pairs requires a deep understanding of the underlying systems. Secure interaction with sets of tag pairs can only practically be exposed as monolithic yes/no decisions for the entire set. Lack of abstractions, in both process and security, are a barrier to new business interactions.

The smart grid will require integration with smart buildings and their associated power capabilities. Abstract models for system interaction will enable large-scale system integrations. Abstract service models will hide underlying system detail while exposing the diverse systems for orchestration.

Security is the application of policy to service. Situation awareness is required of any mature security model. Situation awareness is only useful when applied to abstractions above identity, above process, and above function. Only when these abstractions are defined, can one then define security.

Service abstractions and security abstractions must develop together. Security enables the open provision of business services. Defined services enable the definition of business policies. Service and security together enable open trustworthy interactions with third parties.

1. BACKGROUND

Today's engineered systems are too complex for further integration. Each function is tightly coupled with the next. Integration requires deep domain knowledge of each side of the integration. Multi-domain integrations require deep knowledge of multiple domains. The primary domains for this discussion are Generation systems, Transmission and Distribution SCADA, End Node systems. End nodes include a plethora of systems as even the smallest home may have a half dozen different non-interoperable systems. None of these systems currently communicates using the business semantics and service architectures of the enterprise.

Engineered systems developed in isolation and little overlap with nearby domains or with best practices in enterprise development. Even low level communications share little with nearby domains as a host of non-interoperable low-voltage protocols can be found even within each domain. Since the systems weren't connected, this seemed of little consequence. Now that it has become practical to interconnect both the engineered systems within a facility and systems in multiple sites around the planet, efforts are underway to integrate many systems previously isolated.

Engineered systems have traditionally been integrated at a low or "concrete" level. The geometric increase in complexity that accompanies low-level integration across systems has made such integration increasingly complex. Many current developers and integrators are comfortable with current approaches, which have the advantage of familiarity and result in long backlogs.

Economic forces are driving increasing integration of existing systems, an integration hindered by the growing complexity of integration of these systems. As we build new systems and 'renovate' old ones, there is an opportunity to consider how to link them into a shared infrastructure.

To accelerate these integrations, we must create and leverage a common information architecture. The underlying systems must be properly factored for maximum reusability. Systems will need to accept the output of other systems as input. As systems begin interacting with other systems, we will need a framework of situation awareness, i.e., what system is requesting this service and what is its authority?

These changes will enable the delivery of entire engineered systems as components. Systems engineers will be able to focus on and compete with their core competencies rather than on understanding all the diverse systems on something as large as the North American power grid.

2. LIMITS OF PROCESS-ORIENTED ARCITECTURE

True Scalability and interoperability require abstraction and security. Most control systems today expose name/value tag pairs as their interface. Interaction with exposed tag pairs requires a deep understanding of the underlying systems. Secure interaction with sets of tag pairs can only practically be exposed as monolithic yes/no decisions for the entire set.

2.1. Process Oriented Development

Engineered systems programming is largely procedural. When you receive this signal, energize that relay. Four seconds after this coil reaches temperature, turn on this fan. This style of programming requires access to all the details; hence the name value tag pairs. Integrating two different systems requires a deep understanding of each.

Interoperability of component systems is impossible at this level of integration. Each instance of a control system will have slightly different internal tags. Even two systems with the same part number may have quite different internal components if manufactured a year apart.

This problem is worsened as the number of systems increases. With the domain knowledge required for each new integration, the proportion of systems engineers with enough knowledge of enough domains goes down.

While the engineer looks to maximum efficiency or process, the efficiency of integration decreases.

2.2. Process Oriented Security

Process interactions are targeted only at interactions with other processes that are known a priori. All name/value tags are like all others; no categorical distinctions can be made between them. No metadata is known about the underlying business function.

Without metadata, there is no way to secure one of these systems. Security requires situation awareness. Security is the art of offering the right person in the right situation unimpeded access to functionality. Security requires each systems recognize its relationship to other agents, whether human or automata.

Process oriented security is inherently at the lowest level. Without clear definitions at the level of the system of the business function provided, there can be no recognition of appropriate interactions with external agents. Without recognition of appropriate interactions, there can be no nuances of security, and no distinguishing between external agents. The process is left with only two security modes: full and unrestricted access, or complete restriction of any access.

This limited security applies whether the security is enforced by access lists, by network addresses, or by list based, or by encryption.

3. SEMANTICS AND SERVICE ORIENTATION

In systems, the term service refers to a discretely defined set of contiguous and autonomous business or technical functionality. OASIS defines service as "a mechanism to enable access to one or more capabilities, where the access is provided using a prescribed interface and is exercised consistent with constraints and policies as specified by the service description."

In economics, service is the non-material equivalent of a good. Service provision has been defined as an economic activity that does not result in ownership. A service is the result of a process that creates benefits by facilitating either a change in customers, a change in their physical possessions, or a change in their intangible assets

In engineered systems, the service is not the underlying process, but the reason why that process was procured. The service provided by a Heating, Ventilation, and Cooling (HVAC) system is not the blowing of fans and compression of coolant. The service provided by an HVAC system is the economic provision of healthful and comfortable air. In another situation, the service provided by an HVAC system is the preservation of an economic asset by providing an optimum physiochemical environment. The service is what the owner actually wishes to buy.

3.1. Semantics of Service

As we discover the core services provided by the underlying process, we need to categorize each service. We do this by defining standards names for each function exposed as a service. We refer to these names as the service semantics.

Semantics lets us group similar functions. By properly factoring functions that share the same semantics, we can discover the operational inputs that these functions require. Semantics and the factored operational inputs define the surface of a system.

When different systems share a common surface, we have interoperability. Interoperability does more than let us swap out one system for another. Interoperability lets us interact with different systems over space, at many locations, and over time, as technology changes.

3.2. Security and Situation Awareness

System semantics give us the means to define more nuanced security. Whereas under process, we merely had points, with semantic services, we can see business situations that we can permit or obstruct agents from interacting with.

Let's examine, as an example, the HVAC system whose service is the economic provision of healthful and comfortable air. We may determine that certain classes of business users may adjust the comfort portion of each defined space. Each system may offer up a different set of points as the comfort related settings. Process overlaid with semantics defines situations.

3.3. Security enables Services

Security creates an awareness of who is asking for a service. System semantics names what services are available. Both requester and service are required for situational awareness.

Without nuanced security, systems are unable to expose surfaces. As we define security, the range of services that a system can offer expands. Security is the great enabler of business services.

Abstract surfaces occult the inner working process of each system exposing only the abstract operations as services. The service defines the purpose of each component system within the larger integration and within its local ecosystem. I like to call this purpose the system's mission.

Each building system's first job is to defend its mission. Defending this mission may include preventing all but those with the highest authority (relative to the system) from reconfiguring the system. Integrators get to perform loop tuning; tenants get to modify comfort settings.

3.4. Semantics enable Discoverability

Discoverability is an important feature for systems that can be modified without central engineering control.

Consider networked printers on a modern network. They can be discovered by asking one's system to search for all nearby printers. If you wish, you can print immediately, or you can discover the heterogeneity of the interface. This one has two bins. That one offers color.

When properly implemented, services and their semantic tagging can create the "Plug and Play" self configuring system.

4. EFFECTS ON ENGINEERED SYSTEMS OF SERVICES INTERFACES

Systems that are quite different in complexity and technology can provide the same service. Owners and integrators will be able to compare different systems as to how safe, effective, and economic their operation is without changing the higher level integration.

This reduces the friction on decisions to switch from one service component to another. There will no longer be a large cost of integration associated with each system purchase or upgrade. Competition between system alternatives will be increasingly based on price and performance, and less on compatibility with installed base. This will reduce sales cycles and increase the incentives for innovation.

5. IMPLICATIONS FOR THE POWER GRID

Systems that expose their services using standard semantics become discoverable. These services can be listed in a registry and each registry will include the standard name for the service provided. If there is no registry, but the systems are discovered by some other process, each will still be able to name itself when contacted.

Discoverability is essential for a system as large as the power grid. Discoverability enables grid models to understand building systems as they are installed and changed by building owners and tenants.

Alternately, discoverability of standard services opens up a market for standards based agents, interacting with business and home activities within the building, and with the buildings embedded systems.

An important effect of this model is that the power grid itself must manifest itself to the in-building agent as a service. The service should provide features to analyze the effectiveness of building operations (instantaneous electricity usage) as well as their cost (instantaneous pricing). Power from the grid, with its price, and power from an on-site generator, with its price, and even power from an on-site renewable source are all merely instances of the same service to the on-site agent.

More advanced systems will want to receive metrics of service and reliability from the power source services. Committee members in The Green Grid, a data center operations standards group have already asked for information on immediate projections of reliability from the building transformer and from local distribution. Data center operations want this projected reliability information to "reflect deep domain understanding to produce engineered information that does not require operators to acquire their own domain expertise."

5.1. System Security on the Grid

Significant segments of people and businesses will not give up autonomy over their private resources to any third party. Power Grid assets must provide secure access to their information while not sharing information gleaned from inside the buildings.

In-building agents may be controlled by building owners and tenants or by third parties deputized to make decisions in their behalf. The grid, the services, and other agents must be able to understand the chains of authority that accompany each transaction.

6. IMPLICATIONS FOR THE POWER GRID

A service can abstract the internal operations of each system. This service defines the mission of the internal operations each system. Each building system should defend its mission. Systems that are quite different in complexity and technology can provide the same service. Owners and integrators will be able to compare different systems as to how safe, effective, and economic their operation is without changing the higher level integration.

Services enable security, and security enables allowing the tenant or owner to interact with building systems. Agents can be restricted to which services they interact with, and what performance they request using understandable business rules. This level of abstraction will support internal tenants or third party service managers to safely and effectively interact with the building systems.

Service oriented architectures and integrations make possible large scale interactions. Service discovery enables ad hoc interactions. Services hide implementation details. Service oriented architecture will enable orchestration of building systems including site-oriented energy generation and storage. New business models will take advantage of these new interactions to drive energy use reduction through innovation.

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Biography

Toby Considine has been working with enterprise applications and integration of embedded control systems for 25 years. As a Systems Specialist at the University of North Carolina, Mr. Considine has struggled with the network demands, poor data sharing, and non-scalable security issues posed by last-generation embedded building systems. This work led him to speaking and writing on open discoverable data standards for control systems. For the last five years, Mr. Considine has chaired the OASIS oBIX (open Building Information eXchange) standards committee.

In earlier work, Mr. Considine was for six years on the faculty of the Institute for Facilities Management, running its IT for Facilities Professionals track. Before coming to the University, Mr. Considine worked to integrate other silo processes into the enterprise for companies including The Architect's Collaborative, Reebok, Digital Equipment Corporation, and Southco Distributing.

He also worked on one of the largest of the early public access computer systems, CityNet, and so can claim to be one of the few participants in a DOTCOM meltdown in the '80s. He acquired his respect for the power and limitations process oriented programming writing device drivers for some of the first microcomputers sold.

Rational Agents for Decentralized Environments

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Keywords: Multi-Agent Systems, Distributed and Decentralized Systems, Software Interoperability, Service-Oriented Architectures, Robustness, Communications Stack, Ontologies

Abstract

Given the emergence of new and varied energy producers, consumers, and combinations thereof, software processes and services that work on our behalf must adopt the qualities of intelligent distributed systems to address challenges including: local control of processes, local ownership of data, loose coupling and late binding, authentication and non-repudiation, balancing of competition and cooperation, and graceful degradation. Rational agents provide a basis for achieving the robustness and efficiency we seek. Agents can be owned by different organizations, can respect boundaries of authority and proprietary control, and can represent appropriate interests while working in concert with other agents and human operators to achieve common goals. This approach supports dynamic, decentralized detection of both faults and opportunities, and enables persistent online simulation and optimization. Veterans of the pioneering Agentcities project have demonstrated the importance establishing a multi-layer agent communication stack, realized in abstract, intermediate, and instance levels of concreteness. This approach is especially applicable to the Gridwise Alliance, which can promote standard business process descriptions among its membership. The paper presents the rationale of the agent communication stack, its relevance to energy grid participants, and outlines a specific agent architecture, which provides agent behaviors as services, affording integration with existing and future service-oriented architectures.

1. Challenges of Interoperability

Some of the great challenges of interoperability include: the local control of processes, local ownership of data, authentication and non-repudiation of marketplace entities, achieving a balance of competition and cooperation, determination and implementation of policies and protocols that are fair to participants, all while adhering to both regulated and pragmatic requirements for system robustness.

1.1. Future Generation/Transmission/Consumption: A More Complex Environment

Distributed generation, and the advent of new generation technologies provides potential efficiencies and reduction of the environmental costs of energy. In many cases, a single entity may be both producer and consumer, depending on semi-controllable factors such as demand, and uncontrollable, semi-predictable factors such as local weather. Because of reduced control over the spectrum of generating entities, transmission demands may well be more chaotic than they are today, affected by producer/consumer switching, temperature, overcast, and wind speed. Offsetting some of this variation, monitoring and management of consumption will become pervasive, and endpoints will enjoy additional options in production, consumption, and local energy storage.

1.2. Decentralized Control

The addition of many new parties to the energy grid will introduce new management difficulties, especially for organizations that must maintain spinning reserve to offset potential system failures. Distributed generation facilities will not have the extensive management and business infrastructure of electric utilities, making central coordination impossible. If unexpected changes do occur in the distributed generation landscape, there may not be a human operator to answer the phone, regardless of contractual commitments. This eventuality requires that coordinating entities *at all levels* must maintain models of consumption, production, and reliability, and should continually seek ways to hedge against both physical and economic calamities. Each of these entities will benefit from some sharing of information and models, but it is impossible for a central single entity to obtain complete information about the system, due to both the inherent locality of some variables, and to legal limits of visibility in competitive markets. That said, there is a sizeable opportunity to save money and reduce environmental impact by achieving better and more pervasive control of local energy use. Such control is a pure win for both consumers who avoid high costs, and for producers, who effectively satisfy greater demand with the same capital investment. Pervasive sensors, communication, and multi-level models of energy systems and energy markets can provide both efficiency and robustness.

1.3. Authority, Autonomy, and Discovery in Decentralized Energy Markets

Due to the fact that entities in the new energy environment will play both competitive and cooperative roles, and, because even innocuous information such as the generator maintenance schedules can afford competitors with a pricing advantage, appropriate control of proprietary information is required for maintaining a fair market. Market participants must enjoy a fundamental level of autonomy, but must be able to negotiate that level of autonomy where there is economic benefit. They must be able to lease the authority to control resources and to regain that authority smoothly as leases expire. Additionally, the market itself is likely to become so fluid that any historical directory of participants is at least partially incorrect. Entities must be able to discover markets, opportunities, and other entities *dynamically and opportunistically*, as they become visible and available. Such forms of discovery also permit the rapid reconfiguration of resources, as new generation, storage, and control technologies emerge.

2. Multi-Agent Systems and Service Oriented Architectures

Multi-agent systems (MASs) grew out of early efforts in distributed artificial intelligence, and have become an active area of both research and application. Quoting Katia Sycara[1]: "The characteristics of MAS are that: (1) each agent has incomplete information or capabilities for solving the problem and, thus, has a limited viewpoint; (2) there is no system global control; (3) data are decentralized; and (4) computation is asynchronous." Agents within a multi-agent system confront the same fundamental limitations as do humans, that of *bounded rationality*. They may have access to great amounts of information and may have abilities to model, predict, and decide quickly given the current known state, but agents are always acting with only partial information about the world. A MAS plays a role analogous to that of human society; it provides a context for agents to effectively tackle problems that are too large, or too pervasive for any single individual to solve.

Some features of typical MASs include: Use of specialized agent communication languages (ACLs) languages for inter-agent communication; use of common ontologies to ground the information communicated among agents, use of formal roles for agents to play in a given interaction, explicit interaction protocols to support cooperation, and the use of directory services and subscribe/publish models to permit communication among a changing population of agents. Additionally, recent MAS platforms are typically constructed in layers, providing basic communication at the lowest levels, up to modeling, planning, learning, and, even a degree of introspection at the highest levels.

Many parallels exist between MAS approaches and those of service-oriented architectures (SOAs). Like MASs, SOAs are typically aimed at solving problems in a decentralized environment, often one in which different entities "own" the different components and data involved in and overall process. SOAs use specialized languages for communication, and may subscribe to (formal or informal) ontologies. They often use directory services and subscriptions, have some sense of roles within transactions, and adhere to well-defined protocols. However, unlike MASs, most SOAs are typically aimed at a static problem of constructing a particular, well-defined, persistent application from components. Accordingly, the lifetime of SOA components may be very long, and some components may be relatively monolithic—rather than dynamically emerging to meet demand. Furthermore, SOA components may lack the flexibility and variety of roles that are possible with the elements of a MAS.

3. Rational, Goal-Oriented Agents

Rational, goal-oriented agents provide a basis for achieving the physical and economic robustness and efficiency that is needed in critical infrastructure such as energy systems.

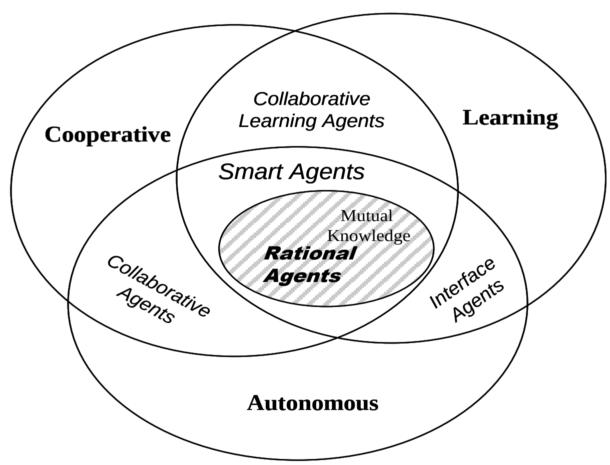

Figure 1. Software Agent Space (adapted from H. Nwana[2])

Figure 1 shows an agent typology derived from an original conceptualization by Nwana in 1996. In this view, the salient features of agent are their abilities to cooperate, to learn, and to behave autonomously. Different emphases among those features provide agents with distinct uses and strengths. The original figure puts "smart agents" at the intersection of autonomous cooperative learning agents, but the typology has recently been extended to include Rational Agents, that maintain mutual knowledge. A key aspect of

Rational Agents is the ability to consider models about the domain of interest, including the models of agents, (themselves and others) agent commitments, and agent capabilities. As mentioned before, these models are incomplete and predictions from the agent's models are necessarily imperfect. However, agent systems are constructed to support effective behavior even when individual actions may be in error.

Agents may be owned by different (legal/organizational) entities and can be constructed to act consistently on the behalf of those entities even while acting in collaboration with agents owned by other entities. In some cases, such as electronic markets, legal entities are better served by lending at least temporary authority to agents, which can react quickly to opportunities, rather than hand-reviewing every suggested transaction. In other cases, the sheer information volume that agents may encounter precludes detailed human oversight, and, organizations are best served by reviewing only the salient information gleaned from agent interaction. However, in either case, the internal and private data that is owned by the entities is preserved (ownership boundary) since its divulgence can represent a competitive advantage to other, competing entities. It is the ability of agents to persistently represent the interests of their associated entities, and, to react in reasonable ways to both opportunities and faults, which makes them particularly well suited to the challenges of distributed generation, control, and energy use.

4. Relevant Work from the Agentcities Experiment

Current Gridwise Alliance members have widely varying goals, capabilities, processes, and terminology that present both challenges and opportunities to interoperability efforts. Veterans of the pioneering Agentcities project, a multi-company interoperability test bed to exercise Foundation for Intelligent Physical Agents (FIPA) standards[3], have wrestled with these problems, and, have demonstrated the importance in establishing a multi-layer agent communication stack, which is realized in abstract, intermediate, and instance levels of concreteness. This approach is especially applicable to the Gridwise Alliance, which can promote standard ontologies and enable common business process descriptions among its membership.

4.1. The Agentcities Interoperability Testbed

The aim of the Agentcities project was to demonstrate interoperability among independently developed agents that followed the FIPA ACL and model of behavior. Though it appears, on the surface, that the FIPA specifications alone may be sufficient for full interoperability, this proved not to be true. In fact, there are many design decisions and points of potential disagreement that do not arise with agents that are developed by a single monolithic organization. The Agentcities project was able to construct a number of applications from disparate agent components, over the 2001-2004 timeframe, but was only successful after extending the specifications for agent behavior, communication, and interaction beyond the FIPA standard.

4.2. The Agentcities Communication Stack

Tables 1, 2, and 3, (from Dale, et al.[4]), illustrate the three levels of concreteness that were found to be necessary to support effective interoperability among independently developed agents and agent applications. In these tables, the *communication context* defines the relation between elements and the domain in which they are interpreted; the *conversation* describes the exchange of messages that comprise a communication episode; a *message* is one atomic communication item transmitted between agents; *content* is the specific information contained in the message, and, *domain descriptors* are the references to the world model that are used to construct the messages.

Layer	Model Level
Communication Context	Agreement on one or more representations or indicators which determine the environment. This might include, for example, logical representations about world states.
Conversation	Agreement on one or more representations for sequences of messages which can be used to express the structure and semantics of message sequences.
Message	Agreement on one or more communication languages which can be used to express communication messages.
Content	Agreement on one or more content languages which can be used to express states of the world and be embedded in messages.
Domain Descriptions	Agreement on one or more representations that can be used to specify descriptions of domains relevant to a communication episode.

Table 1: Abstract Model Level Definitions

Layer	Intermediate levels
Communication Context	Agreement of the definition of elements that are part of the world and can be used by participants in the communication episode to interpret the meaning of statements.
Conversation	Agreement on a subset of message sequences and conversation patterns which are standard for the environment. These definitions represent commonly used concrete instances of the whole range of possible conversations that could be expressed in the chosen model languages.
Message	Agreement on a set of message types or message templates that are used in the interoperability environment.
Content	Agreement on a set of content types or content templates that are used in the interoperability environment.
Domain Descriptions	Agreement on a set of descriptions for domains that are available in the interoperability environment, for example, an ontology library.

Table 2: Intermediate Level Definitions

Layer	**Instance Level for a Single Communication Episode**
Communication Context	Use of a set of specific elements of the world that are relevant to a particular communication episode.
Conversation	Use of one or more specific conversation patterns (often only one) used for a particular communication episode.
Message	Use of one or more specific message types used in a particular communication episode. Often this choice is guided by the selected communication pattern.
Content	As for the Message level: Use of one or more specific content expressions in each of the Messages sent in the Communication Episode.
Domain Descriptions	Use of one or more specific domain models in the communication episode.

Table 3: Instance Level Definitions

4.3. Significance of the Communication Stack to Grid Interoperability Standards

Interoperable software systems, regardless of their architecture, must share a common view that permits effective communication. For the simplest static systems, the common view consists of message and data definitions, for more capable systems, there must be agreement about how to interpret metadata, while still more capable systems require commonality among models and model elements. Industry standards bodies are uniquely positioned to create standard ontologies that facilitate the semantic levels of communication among components. These ontologies provide metadata about all relevant referents in the domain of discourse and formally describe the relations between concepts in that domain. Without unified, standard ontologies, groups will invariably develop partial or ad-hoc conceptualizations of domain elements, and those domain models very likely be incompatible, and may ultimately become a barrier to the composition of services from existing capabilities. Content and domain descriptions within the agent communication stack can be grounded in these formal ontologies, enabling decoupled systems to cooperate in both persistent and occasional applications.

5. HERMES Agent Platform

HERMES is a multi-agent platform that provides agent behaviors as services, affording integration with existing and future SOAs. It is constructed in layers that extend from basic message transport, up to high-level planning and domain-modeling. The HERMES platform is a conceptual descendant of several pre-existing agent approaches and standards, including RETSINA[5], DECAF[6], FIPA[7], and JADE[8].

5.1. Wrapping Services with Agent Behavior

SOAs have recently emerged from a long evolution through completely proprietary IT systems that required end-to-end uniformity and single-vendor solutions, to solutions constructed from a few prime subsystems involving multi-year $MM integration efforts, to today's component-ware, in which service providers, service brokers, and service requestors may be assembled rapidly to meet emerging business needs.

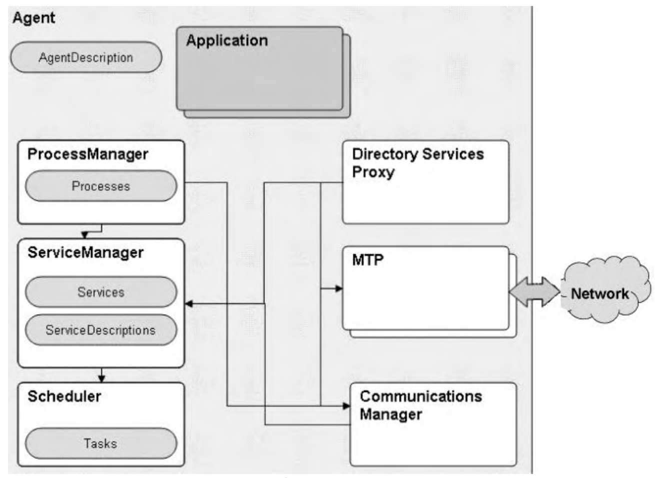

Figure 2: Principle Features of an Individual Hermes Agent

As illustrated in Figure 2, HERMES agents can offer their capabilities as applications in a standard service-oriented environment, and can, conversely, "agentify" existing SOA components.

5.2. Distributed Processes in HERMES: Explicit Models of Interaction

An agent platform provides more than individual agent interfaces. It also provides mechanisms that support agent collaboration to accomplish tasks. In the HERMES environment, a useful abstraction for such collaboration is the multi-agent process, which is typically accomplished by several agents playing specialized roles within a defined interaction protocol. To facilitate the definition of these multi-agent processes, HERMES provides a process language, which is an extension of the pre-existing Business Process Execution Language (BPEL), and offers a process editor for visually constructing processes and for monitoring their execution.

Figure 3 illustrates a simple-request process, as constructed in the HERMES process editor, which uses the Eclipse Rich Client Platform. This process can be invoked, tested and monitored within the editing framework, enabling rapid development and debugging of complex, multi-agent applications.

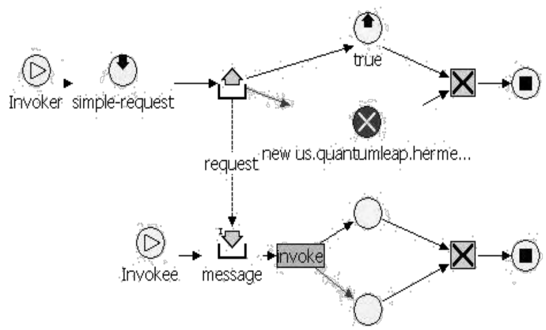

Figure 3: The Simple-Request Process Interaction Diagram

Figure 4 lists the process primitives that are used to construct multi-agent processes. To date, the process editing environment has been used to define several important interaction protocols, including: *fipa-request*, *centralized-execution*, *simple-request* and *contract-net*. Extensions of these protocols may be particularly relevant to the challenges of scheduling resources to satisfy physical energy demands efficiently in a competitive environment[9,10]. Additionally, beyond bidding-style protocols to perform allocations, agents with sufficient models of market costs and projections of ongoing demands can play the role of market-makers for efficiently brokering the best matches on the basis of local market optimality[11]. This approach can be cascaded to multiple levels of a hierarchy, with brokers at each level acting persistently to optimize the value of the market that it manages.

5.3. Pro-activity Amongst Rational Agents (PARA)

PARA is a high-level planning, reasoning, and decision-making capability that runs on top of HERMES to model complex and dynamic distributed systems. It provides an event calculus-based[12] planning engine, that can be deployed as a component within a HERMES agent. The logic framework extends standard SOAs by wrapping services of an agent with meaningful descriptions (meta-data) that specify the service pre-conditions and effects within a formal model of the application domain. The driving force behind an agent's activity is a set of goals, which can be triggered by events in the agent's environment (sensor data, communications), or can be given by other agents or users. Each agent is able to autonomously determine a sequence of actions to achieve their goals and each goal or action can be related to information and resource requirements. A PARA agent is able to constantly evaluate its environment and adjust and prioritize its actions as a result of new events so that they are in line with its existing set of goals. High-level cooperation is enabled by sharing goals and establishing commitments to goals among agents, which allow agents to coordinate activities without sharing the details of how each agent will achieve its goals. At the same time, PARA agents retrieve information and secure resources that are required to accomplish their goals. PARA provides novel extensions to traditional event-based planning in that it is *reentrant*, supporting continual re-planning, and, that it reasons about *concrete time-points*, permitting agents to synchronize activities without recourse to polling or other costly control mechanisms.

Node Type	Icon	Description
Activity		calls a service
And		splits the execution into multiple parallel branches of execution or joins multiple branches in a synchronized fashion
Condition		allows the flow to follow one of multiple paths
Fail		signals a failure result from the service
Invoke Entry		represents a service interface to the process
Invoke Return		returns a result from within a process for a particular service
Receive		receives a message blocking the flow
Role		starts a process role
Script		executes an arbitrary script
Send		sends a message in a process
Stop		terminates the flow of a process
Timeout		pauses in the process
Trigger		blocks the flow of a process until the trigger event occurs
XOr		introduces a conditional split into a process

Figure 4. Icons and Semantics for the HERMES Process Editor

6. Conclusion

We have presented arguments that an agent-view of services can support much of the flexibility, robustness, and configurability demanded by the emerging distributed-generation environment. To get the most out of agent platforms, there must be broad agreement on both the software interfaces that permit interaction, and on the semantic grounding that supports shared models about the domain and domain participants. Ongoing interoperability among separately developed dynamic components is particularly challenging and requires powerful tools both for construction and for monitoring of the resulting processes.

We are approaching a point where every energy component, from refrigerators, to home generators, to distant nuclear reactors, will be accessible to some level of pervasive monitoring and control. That control will not be effective unless there is consistency among the models of system participants. Multi-agent communication and coordination approaches, coupled with standard ontologies, can catalyze standardization in both programmatic interfaces and in shared conceptual models that are a prerequisite for interoperability.

Biographies

Jonathan Dale is Director of Distributed Systems at Quantum Leap Innovations. With 15 years of experience in Multi-Agent systems, Web Services and the Semantic Web, including work as a Senior Researcher with Fujitsu Laboratories of America, Jonathan's research efforts have focused on the next generation of agent–based technologies for the Internet. He has been actively involved in the work of many industrial standards organizations, such as the World Wide Web Consortium (W3C), the Foundation for Intelligent Physical Agents (FIPA) and the Agentcities Task Force (ACTF). Jonathan's work has become a significant contribution to standards bodies has been written into the official specifications in for agents, Web Services and the Semantic Web. A co-founder of the Agentcities initiative and member of the FIPA Architecture Board, Jonathan has been working within the Global GRID Forum (GGF) as part of the Semantic GRID workgroup. He has published numerous papers in journals, magazines, conferences and workshops within his field and has written a number of patents which are currently being reviewed by the US Patent Office. Jonathan earned his PhD in Computer Science at the University of Southampton, UK, and his BS with Honours in Computer Science at Staffordshire University, UK.

Apperson H Johnson is Chief Science Officer at Quantum Leap Innovations. Apperson Johnson has been working in applied Artificial Intelligence since the early 1980's, having been a principal author of a natural language interface system, several inference systems, several knowledge representation systems, an object oriented modeling system, a robust scaleable optimization system, and a system to support automatic markets for complex products. A Summa Cum Laude graduate from the Chemistry-Biology program in West Chester State University, he also holds a Master's degree in Computer Science from the University of Delaware, where he occasionally teaches. Apperson is the chief technical author of 3 issued US patents and has 19 patents pending.

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The Illinois Institute of Technology Perfect Power System Prototype

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Abstract

The Galvin Electricity Initiative is undertaking the task of demonstrating and open sourcing an improved design for the delivery of electric power. By applying continuous improvement methods to the elements of the United States power grid, the Initiative hopes to achieve the universal adoption of a system design that successfully meets the power needs of every consumer.

Currently at a "tipping point" in its need for a more efficient and reliable electric power system, the Illinois Institute of Technology (IIT) collaborated with the Galvin Electricity Initiative, S&C Electric, Endurant Energy and Commonwealth Edison (ComEd) to explore system renewal. The team utilized quality principals to design a prototype "Perfect Power" system for the IIT campus. The prototype will demonstrate that cost-effective electric power can be delivered to the consumer precisely as that consumer requires it, without failure and without increasing costs.

The Initiative's Perfect Power model includes the following elements:

- Redundant transmission and distribution supply
- Self-sustaining infrastructure
- Intelligent distribution system and system controllers
- On-site electricity production
- Demand response capability (temperature setbacks, lighting, major loads)
- Sustainable energy systems and green buildings/complexes
- Technology-ready infrastructure

1. INTRODUCTION

In 2005, former Motorola CEO Robert W. Galvin founded The Galvin Electricity Initiative, assembling a team of top power innovation leaders and challenging them to apply Six Sigma® quality principles to the problem of electric power quality and reliability.

The Initiative is leading a campaign to develop a pathway for entrepreneurs and utilities to transform today's power system into one that cannot fail the customer – The Perfect Power System. The Perfect Power System is reliable, secure, efficient, and customer-focused. It is tailored to each end-user so it meets their needs perfectly. The Perfect Power System incorporates smart microgrids and control technology, distributed generation, combined heat and power, and renewables.

In January of 2006, the Illinois Institute of Technology and Commonwealth Edison agreed to work with the Galvin Electricity Initiative to develop the first Perfect Power System prototype at IIT. Mr. Galvin's close relationship with the school and ComEd CEO John Rowe's current chairmanship of the board of trustees made IIT a logical choice. In addition, IIT meets several criteria that make it an ideal pilot site for a next-generation power system:

- It is located within the PJM independent service operator territory with access to real time pricing;
- It owns its electric distribution system; and
- It has a robust electrical engineering program.

IIT, Commonwealth Edison (ComEd), the Galvin Electricity Initiative, S&C Electric and Endurant Energy collaborated on the Perfect Power Prototype. This collaboration is a model for bringing stakeholders together to find "win-win" solutions that benefit both customers and the greater power grid.

2. IIT'S EXISTING POWER SYSTEM

IIT's current power system relies on an aging infrastructure that is not fully meeting its current demand and will become increasingly challenged as the university grows. IIT is presently experiencing an average of three outages per year. These outages disrupt classes, destroy key experiments, damage equipment, and force staff to schedule experiments for the evening to minimize risks..

IIT's present peak load is approximately 10MW, drawing its utility power from a single ComEd area substation. Its 8 MW of on-site gas turbine cogeneration was placed in standby mode in late 1990 in response to a favorable load retention rate offered by ComEd..

The campus distribution system employs redundant building feeds and the campus load is divided between two substations, north and south. . Switching is manual and fault detection is non-existent. In the event of an outage, considerable time is taken in identifying the fault location and in reconfiguring the system to bring buildings back online. In addition, manual reconfiguring has led to cable damage and personnel safety issues.

The typical campus building distribution system consists of two manually-switched 4.16kV feeds from a single substation with manual backfeed capability to the other substation. Power is then distributed to a number of panels on each floor where loads including lighting, fan, computer, and in many cases, window unit AC loads are served. Heating is supplied by the school's current high-pressure steam system.

IIT has deployed over 2MW of standby generation to date and will continue to add local electricity generation, UPS, and demand response capability. This will aid IIT in its drive to increase reliability and to manage energy costs and will supplement existing plans to increase campus energy efficiency. IIT is in the middle of a campus wide upgrade of windows, lighting, and heating systems aimed at lowering IIT's costs and carbon footprint.

3. ANALYZING IIT'S SYSTEM NEEDS AND FAILURE MODES

The Galvin Electricity Initiative applied Six Sigma quality principals to IIT's power system with special focus on the failure modes and effects analysis (FMEA). The team identified each point in the system that is likely to break down (failure modes), tracked the effect of each possible failure and prioritized it based on a scale of severity and probability. Failure modes with both a high probability and severity would be addressed though design changes and replacement while those scoring low can be resolved through detection and mitigation.

4. THE PERFECT POWER SYSTEM DESIGN

IIT's system design features built-in redundancies, intelligent technology, a master controller system, on-site generation, and demand-response capabilities – all key characteristics of a Perfect Power System. The paragraphs below describe how these components will be integrated into the system.

4.1 Redundant Transmission and Area Substation Supply

Background: Since 2003's great Northeast blackout, considerable attention has been paid to updating and automating transmission functionality and controls. The achievement of redundant or self-healing transmission supply to an area substation provides the most important step in stabilizing an area's power reliability. This highly motivated work, which is ongoing with significant federal backing, allowed the team to focus our efforts below the area substation level.

What it will look like at IIT: Prior to the Galvin Electricity Initative IIT and ComEd were pursuing a redundant power feed from a second ComEd substation to a new east campus. However, the need for an east campus substation will likely be eliminated by redundancies achieved through Perfect Power System upgrades.

4.2 Self -Sustaining Infrastructure

Background: Self-sustaining electric infrastructure is crucial for the success of a Perfect Power System. The many factors that can negatively impact power supply must be mitigated automatically by the system if outages are to be avoided.

What it will look like at IIT: An intelligent distribution system, coupled with on-site generation, demand response capability, intelligent controls and sustainable building technology will combine to achieve a true self-sustaining or self-healing electric infrastructure at IIT.

4.3 Intelligent Distribution System

Background: An intelligent distribution system consists of properly-sized cable and transformers capable of carrying the full expected load; feeder redundancy to offer an alternate power supply to buildings where power has been interrupted; automated breakers and switches to execute the split-second isolation of faults; automated restoration; and a communications system capable of orchestrating this split-second reconfiguration of the system.

What it will look like at IIT: IIT's Perfect Power System model will build upon S&C Electric's High Reliability Distribution System (HRDS) concept. The team separated the campus into logical groups of buildings that will each be placed on a feeder loop. Each loop will be continuously energized. In the event of a loss of one section of cable or a switch, the design concept provides for the automatic isolation of faults without interruption of power to any loads. Re-closure is not necessary, but is available.

This system loop configuration is made effective by the use of intelligent switching and breaker coordination technology which provides for rapid assessment and isolation of faults via advanced communications.

4.4 On-Site Electricity Generation

Background: Generating electricity onsite is a key component of Perfect Power in situations where redundant utility distribution is unavailable or power reliability requirements exceed the grid capability, . Reliability is increased in the form of electricity storage, UPS, back-up generation, and continuous generation. In addition, on generation can reduce energy costs by offsetting peak electricity pricing or mitigating the risks of purchasing electricity in real time.

What it will look like at IIT: The team plans to supplement the 8 MW of gas turbine generation with two 2MW gas engine generators at the substation level. This generation, in concert with building or load-specific uninterruptible power supply (UPS) will be able to carry all of the campus's critical loads in the event of a loss of utility power. In the rare cases where HRDS and substation-level generation will not provide Perfect Power System reliability, building-integrated power systems or load-specific generation will be employed.

4.5 Demand-Response Capability

Background: Utilities compensate customers who can alleviate stress on the grid due to peak demand conditions. The ability to respond to the utility's need to reduce demand on the grid is not only a source of revenue but is critical to Perfect Power beyond the customer site level.

What it will look like at IIT: Demand-response control will be integrated into the campus in two ways. In some cases, building circuits can be switched off by the HRDS controller. For more flexibility and precision, additional load controllers will be installed on certain loads and circuits for demand-response control. The loads will be operated by a demand-response load controller.

4.6 Intelligent Perfect Power System Control

Background: In order to function correctly, Perfect Power Systems require sophisticated monitoring, communication and supervisory control capability. A master controller is built into each system to monitor and trend critical parameters and determine the system state. It then changes system operating conditions to maintain the system within the specified limits of operation.

What it will look like at IIT: At IIT, the Intelligent Perfect Power System Control (IPPSC) will:

- Start and stop local generators and storage devices;
- Control local loads based on predetermined sequence of operation and load reduction priority schemes;
- Automatically switch loads to alternate transformers, campus feeds and substations as required by conditions; and

Place a building or the entire campus in island mode.

4.7 Sustainable/Green Building Technology Capability

The Perfect Power System will help IIT achieve its sustainability goals by reducing pollutant and carbon emissions through energy conservation, leveraging renewable resources, and reducing peak demand that strains the distribution system and increases energy costs. This includes energy efficiency upgrades, efficient hot water loops for building clusters, building envelope improvements, and advanced building controls.

5. BENEFITS OF PERFECT POWER FOR IIT

The proposed Perfect Power System prototype addresses a number of existing and future campus needs. The campus is outgrowing the electrical distribution system described above in several areas and critical components are reaching their end of life. The prototype provides an opportunity to replace worn-out components while applying the Perfect Power System design in such a way as to eliminate extended outages at the campus.

5.1 Avoided Distribution System Upgrades

ComEd has indicated that the Perfect Power prototype will defer pending upgrades to the Fisk substation totaling approximately $2,000,000. In addition, planned new housing on east campus combined with expanded academic and research facilities throughout campus will exceed the capacity of the current site electricity distribution system. IIT was pursuing a third substation on east campus at a cost of over $5,000,000. The Perfect Power design will meet the new electricity demand and address reliability concerns without installing a new substation.

5.2 Reduced Energy Costs

IIT and ComEd are located in the Pennsylvania, New Jersey, Maryland (PJM) Independent System Operator (ISO). This provides for the opportunity to purchase electricity in real time. The Perfect Power system positions IIT to purchase lower cost real time electricity and reduce peak energy demand which costs more. An analysis which compared the current electricity procurement agreement against the 2005 and 2006 real-time prices, determined that IIT would have saved approximately $1,000,000 per year purchasing electricity in real time while using the site generation to cap the electricity price.

5.3 Improved Reliability

The Perfect Power System prototype will ensure that no single failure in any of the distribution system feeder circuits will result in an interruption of power. In addition, the site generation will be expanded from 8 to 12 MW to carry the entire campus electricity demand during ComEd supply interruptions. This will provide for the automatic restoration of electricity to all campus facilities within 5 minutes of a ComEd supply outage. Critical campus loads/equipment have Uninterruptible Power Sources locally.

5.4 Improved Safety

The Perfect Power system will provide IIT with a significantly more robust energy system that can respond to weather, aging, and other threats, ensuring power to students, teachers, and tenants during emergencies. In addition, the Perfect Power system will automate high voltage switching throughout the campus, eliminating the potential for personal and equipment damage resulting from human error.

5.5 Economic Development

The proposed improvements to the IIT electrical distribution system and the Perfect Power prototype position IIT as a test bed for research and education opportunities. IIT can serve as a living laboratory for the most advanced distribution system concepts and control technologies. Implementation of the perfect power at IIT will provide a powerful resource for attracting students and government/industry funding. The Electrical Engineering school expects to raise an additional $1 million per year due to the added campus features and functions.

6. CONCLUSION

The IIT prototype provides a glimpse of a new electricity system paradigm where utilities and customers work together to build local Perfect Power systems that serve both the customer and the greater power grid to bolster reliability and efficiency across the entire U.S. power system.

A power system that never fails to meet the customer’s every functional need but is out of the financial reach of that customer is not perfect. Perfect Power meets the economic needs of the customer as well as the functional. The IIT Perfect Power prototype demonstrates that the very improvements that make it functional also make it affordable – not only saving the customer money but in some cases producing revenue.

Biography

John F. Kelly is currently for the Vice President of Technology Solutions at Endurant Energy, an energy technology services firm developing sustainable energy systems for buildings, major land developmetns, and cities across the United States. Mr. Kelly is currently leading a team of experts in the development of a "perfect power" or sustainable energy system for the Illinois Institute of Technology campus and the Hudson Yards development in New York City. Prior to joining Endurant, Mr. Kelly was the Director of Distributed Energy Technologies for the Gas Technology Institute in Des Plaines, Illinois, where Mr. Kelly established GTI's Sustainable Energy Planning Office.

Don Von Dollen is the Program Manager for the Electric Power Research Institute (EPRI) Communications and Data Integration Group and the leads the IntelliGrid Program. The IntelliGrid Program is focused on accelerating the transformation of the power delivery infrastructure into the intelligent grid needed to support our future society through a unique collaboration of public and private stakeholders. Mr. Von Dollen joined EPRI in 1991 and has held positions as Applications Manager for Power Delivery and Markets, Program Manager for Underground Transmission and Project Manager. Mr. Von Dollen has managed EPRI’s superconductivity research program including wire and cable development, and research projects relating to transmission cable systems.

Reliability-Based Methods for Electric System Decision Making

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Keywords: decision-making, electric system, RBDO, FORM, uncertainty

Abstract

The purpose of this paper is to develop a methodology that utilizes reliability-based optimization to solve complex electrical grid usage problems. With electrical power grids, as with many complex systems, complicated decisions must be made at both the local (user) and global (electricity provider) levels; all decision makers have independent, often conflicting, objectives, further complicating the decisions. In order to incorporate both levels of decision making (and resulting interaction effects between the decision makers), a reliability-based optimization approach can be utilized which incorporates local decision makers' preferences by enforcing probabilistic constraints on the overall optimization problem (e.g., sectors A and B need a particular amount of power and each sector has a different criticality level). This ensures that the optimized decisions made at the global level satisfy the basic requirements of the local decision makers (e.g., to deliver power to critical sectors). The uncertainty in this approach is incorporated through an efficient first order reliability method (FORM), an analytical approximation to failure probability calculation, rather than traditional, computationally expensive simulation-based methods (such as Monte Carlo sampling). Usefulness of this methodology is shown through several example problems.

1. INTRODUCTION

As demand increases nationwide for electrical power, the nation must look for intelligent approaches to managing electrical distribution. This requires the development of an electricity management approach that determines the optimal allocation of power to subsystems such that the cost of power is minimized.

In order to achieve this, complex electrical grid usage problems require the interaction of individuals at both local and global levels. At the local level, users expect power to be available on demand (i.e. with 100% reliability). At the global level, electricity providers are struggling to meet the demands of their customers in the most cost efficient manner possible. Thus, it benefits the electricity providers to have the minimum amount of power available so as not to waste electricity when it is not being used by customers. These objectives are inherently competing as maintaining electrical service availability for users is costly. Additionally, the criticality of some infrastructures (e.g. hospitals, police stations) requires greater certainty of power availability than the average user. Combining these factors results in a complicated decision making problem.

This paper develops a methodology for electric system decision-making at both a local and global level. It begins by discussing a basic problem formulation for local and global decision making to facilitate an interoperable electric grid. The detailed mathematical approach behind this methodology is then discussed. Sample problems employing this methodology are demonstrated. Finally some conclusions and recommendations for problem extensions are discussed.

2. PROBLEM FORMULATION

The goal of this methodology is to develop an approach for electric system usage which incorporates the needs of both local and global decision makers. The approach taken to achieve this goal is to make decisions at a global level which satisfy the constraints of local users. A global decision maker refers to the electricity provider, and it can be a national power company or a city-wide power company, for example. A local decision maker, on the other hand, is an electricity user, and can include an entire city's consumption or a particular sector of society (such as a hospital). For the remainder of this discussion, electric system decisions will take the form of adjusting the power output of generators which, by virtue of their physical connections, can provide power to various sectors (users) of society. Figure 1 shows an example electric grid in which this type of decision making may be necessary for providing power to a hospital, police department and fire department. The global decision maker (in this case, a city's utility company) must make a decision to provide power via any of the four generators to the three sectors. While it may seem obvious at first to operate only generator 2 (since it provides power to all sectors), further analysis may indicate that a combination of power to the other three generators may be optimal. This is due to the fact that one of the three sectors may be seen as more critical. This critical sector may require a greater certainty of power availability.

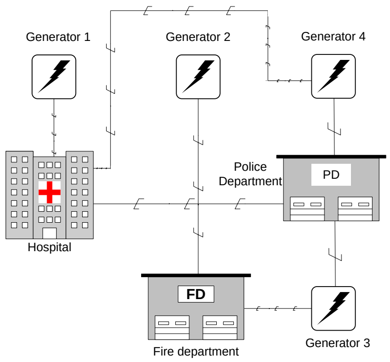

Figure 1: Electric Grid Illustration

In order to make electric system decisions as described above, this paper proposes the following problem formulation:

$$\begin{aligned} &\min \text{Cost} = \sum_i C_i d_i \\ &\text{s.t.} \left[\sum_i PP_{ij} d_i\right] - PD_j \geq 0 \end{aligned} \qquad (1)$$

where i is the index of generators in the power system, C_i is the cost associated with the i^{th} generator, d_i is a decision variable indicating the power level associated with the i^{th} generator (defined on [0,1] where 0 indicates the generator is off and 1 indicates the generator is operating at 100% capacity), j is the index of sectors in the power system, PP_{ij} is the power provided by the i^{th} generator to the j^{th} sector, and PD_j is the total power demand of the j^{th} element in the system.

In Eq. (1), the objective is to minimize the global decision maker's (in this case, the electric company's) overall cost of power generation, given constraints on the required power imposed by sector users. This formulation ensures that both local and global demands are being met. While the optimal decision of Eq. (1) is not globally optimal (as the global decision maker's optimal cost is $0 and the local decision makers would prefer to have all generators delivering power to their sector at 100%), it is a solution which is satisficing to all the involved decision makers. That is to say, the decision makers regard the solution as "good enough" while recognizing that it is not optimal for their own self interests [16]. This concept is essential when dealing with complex, interoperable systems. Sacrifices must always be made in order to obtain a solution that all involved decision makers find acceptable.

This formulation assumes complete certainty with regards to power provided and power demanded. This is not accurate in the context of a real world application. Therefore, the following formulation extends Eq. (1) to include uncertainty in PP_{ij} and PD_j:

$$\begin{aligned} &\min \text{Cost} = \sum_i C_i d_i \\ &\text{s.t.} P\left(\left[\sum_i PP_{ij} d_i\right] - PD_j \geq 0\right) \geq P_{crit_j} \end{aligned} \qquad (2)$$

where P_{crit_j} is the criticality probability associated with the j^{th} sector, and all else is as before. Additionally, the constraint which refers to the power demand vs. the provided power is now defined probabilistically. That is, the net power must be delivered the j^{th} sector with a probability of at least P_{crit_j}. Cost is assumed to be deterministic for the purposes of this formulation.

This problem formulation is similar to the reliability-based design optimization problem formulation, which is discussed in the following section.

3. RELIABILITY-BASED DESIGN OPTIMIZATION

Reliability-based design optimization (RBDO) is concerned with finding a set of design variables for a given engineering system such that a given objective function (minimization of cost) is optimized and the design requirements (power demand) are satisfied with high probability. As mentioned earlier, the problem formulation for RBDO is the same as in Eq. (2). Within the probabilistic constraint, $\left[\sum_i PP_{ij} d_i\right] - PD_j$, which is generally denoted as $g_i(\ )$ and is referred to as a performance function in the RBDO literature, is formulated such that $g_i < 0$ indicates failure, $g_i > 0$ indicates success, and $g_i = 0$, the boundary between failure and success is referred to as the limit state.

There are two steps in solving Eq. (2). Step 1 is reliability analysis, i.e., evaluation of the probability constraint. Step 2 is optimization. Step 1 is discussed in detail below, focusing on a first-order approximation to calculate the probabilistic constraint in Eq. (2). Methods under step 2 are reviewed later in this section.

<u>Step1</u>: Analytical calculation of $P(g_i \leq 0\ )$ requires the evaluation of the integral of the joint probability density function (pdf) of all the random variables over the failure domain, as

$$P(g_i(d,x) \leq 0) = \int_{g_i(d,x)\leq 0} f_x(x)dx \qquad (3)$$

where d is the set of decision variables and x is the set of random variables.

This integral poses computational hurdles since it can be difficult to formulate the joint probability density explicitly and integration of a multidimensional integral may be difficult. Therefore, numerical integration methods such as Monte Carlo simulation or analytical approximations such as first-order reliability method (FORM) or second-order reliability method (SORM) are commonly used in mechanical systems reliability analysis. Monte Carlo simulation requires multiple runs of the deterministic system analysis and can be very costly. On the other hand, analytical approximations such as FORM and SORM are very efficient, and have been shown to provide reasonably accurate estimates of the probability integral for numerous applications in mechanical and structural systems. Detailed descriptions of these methods and computational issues are provided in [1, 5, and 7].

In FORM, the variables, x, which may each be of a different probability distribution, and may be correlated, are first translated to equivalent standard normal variables u. For uncorrelated normal variables, this transformation is simply $u_i = \dfrac{x_i - \mu_i}{\sigma_i}$. (Later, this concept is expanded to include variables that are non-normal and/or correlated). The limit state and the failure and safe regions are shown in Fig. 2, in the equivalent uncorrelated standard normal space u.

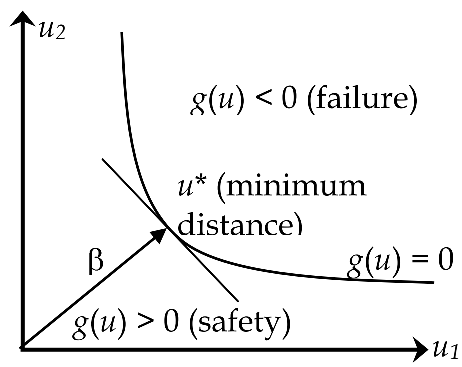

Figure 2: Illustration of limit state and failure and safe regions

The failure probability is now the integral of the joint normal pdf over the failure region. The FORM replaces the nonlinear boundary $g_i = 0$ with a linear approximation, at the closest point to the origin, and calculates the failure probability as

$$P_F = P(\, g_i(d,x) \le 0\,) = \Phi(-\beta_i) \tag{4}$$

where P_F is the failure probability, Φ is the cumulative distribution function (CDF) of a standard normal variable and β_i is the minimum distance from the origin to the i^{th} limit state. Thus, the multidimensional integral in Eq. (3) is now approximated with a single dimensional integral as in Eq. (4), the argument of which (i.e., β_i) is calculated from a minimum distance search. The minimum distance point u^* on the limit state is also referred to as the most probable point (MPP), since linear approximation at this point gives the highest estimate of the failure probability as opposed to linearization at any other point on the limit state. (A second-order approximation of the failure boundary is referred to as SORM, where the failure probability calculation also requires curvatures of the limit state).

The minimum distance point (or MPP) u^* is found as the solution to the problem:

$$\min \beta_i \tag{5}$$

$$\text{s.t. } g_i(d,x) \le 0$$

A Newton-based method to solve Eq. (5) was suggested by Rackwitz and Fiessler [13]. Other methods such as sequential quadratic programming (SQP) have also been used in the literature [6] and [19].

For non-normal variables, the transformation to uncorrelated standard normal space is $u_i = \dfrac{x_i - \mu_i^N}{\sigma_i^N}$, where μ_x^N and σ_x^N are the equivalent normal mean and standard deviation, respectively, of the x variables at each iteration during the minimum distance search. Rackwitz and Fiessler [13] suggested the solution of μ_x^N and σ_x^N by matching the PDF and CDF of the original variable and the equivalent normal variable at the iteration point. Other transformations are also available in [2, 11, 12, and 14].

If the variables are correlated, then the equivalent standard normals are also correlated. In that case, these are transformed to an uncorrelated space through an orthonormal transformation of the correlation matrix of the random variables through eigenvector analysis or a Cholesky factorization [7]. The minimum distance search and first-order or second-order approximation to the probability integral is then carried out in the uncorrelated standard normal space.

The minimum distance search typically involves five to ten evaluations of the limit state (and thus system analysis), and then the probability is evaluated using a simple analytical formula as in Eq. (4). Compared to this, Monte Carlo simulation may need thousands of samples if the failure probability is small, thus making Monte Carlo methods prohibitively expensive for solving large scale stochastic optimization problems.

Since the limit state functions involved in this problem formulation are linear in the random variables, and the random variables are assumed to be normal, FORM will be accurate. Second order estimates [3, 8, and 18] of the failure probability can also be used when the limit state is nonlinear, but due to the simplicity of the limit state function in this paper, second order methods are not found to be necessary.

The minimum distance point may also be found using a dual formulation of Eq. (5) as

$$\min \ g_i \ (d,x) \tag{6}$$

s.t. $\| u \| = \beta_{crit}$

This dual problem may be referred to as inverse FORM, and is used in the optimization (step 2) in this paper. In this formulation, β_{crit} is set to value corresponding to P_{crit}, as $\beta_{\mathrm{crit}} = -\Phi^{-1}(P_{\mathrm{crit}})$.

Step 2: In many implementations of reliability-based optimization, the probability constraint in Eq. (2) is usually replaced by a quantile equivalent, i.e., by a minimum distance constraint, as

$$\begin{aligned} &\min Cost(d) \\ &\text{s.t.}\, \beta_i \geq \beta_{\mathrm{crit}} \end{aligned} \tag{7}$$

where β_i is the minimum distance computed from Eq. (5). Alternatively, the dual formulation has also been used, based on Eq. (6), as

$$\begin{aligned} &\min Cost(d) \\ &\text{s.t.}\, g_i(d,x) \geq 0 \end{aligned} \tag{8}$$

where g_i (d,x) is computed from Eq. (6).

Since the reliability constraint evaluation itself is an iterative procedure, the number of function evaluations required for reliability-based optimization is considerably larger than deterministic optimization. A simple nested implementation of RBDO (i.e., reliability analysis iterations nested within optimization iterations, as in Figure 3) tremendously increases the computational effort, and as a result, several approaches have been developed to improve the computational efficiency, typically measured in terms of the number of function evaluations required to reach a solution.

In decoupled methods [6, 15, and 19], the reliability analysis iterations and the optimization iterations are executed sequentially, instead of in a nested manner (refer to Figure 4, where OL means optimization loop and RL means reliability loop). This is done by fixing the results of one analysis while performing the iterations of the other analysis. Single loop methods [9, 10, and 17] perform the optimization through an equivalent deterministic formulation which replaces the reliability analysis constraint with the equivalent KKT condition at the minimum distance point on the limit state. Several versions of decoupled and single loops have been developed, based on whether direct or inverse FORM is used for the reliability analysis step. Note that FORM is the key to all these efficient RBDO techniques. Further information on the use of FORM in various RBDO formulations can be found in [4].

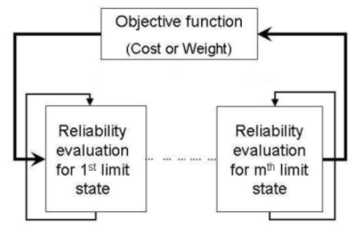

Figure 3: Illustration of Nested RBDO Method

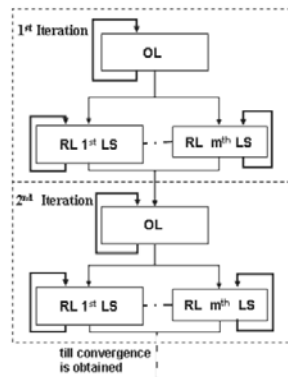

Figure 4: Illustration of Decoupled RBDO with Inverse FORM

For the purpose of cost optimization in this paper, a decoupled method of RBDO developed in [6] is chosen for reducing the number of function evaluations. In the cost optimization, a deterministic optimization is performed which determines a starting point for the reliability analysis. This deterministic optimization follows the formulation in Eq. (1) with the mean values of the design variables serving as the values for the random variables. This optimization yields a set of generator settings (d's). These setting are then passed to the reliability analysis. The reliability analysis then calculates the power demand and power provided (x's or most probable points, known as the MPPs) in the original variable space for the individual limit states, as outlined in Eq. (8). The MPP values are then fed back to the deterministic optimization and these values replace the random variable values (taken as the variable mean values in the first iteration). This process continues until convergence is reached on both a configuration and the MPP values. This process is outlined in Figure 5 below.

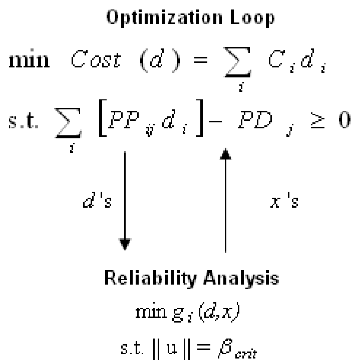

Figure 5: Decoupled Optimization Flowchart

The cost optimization is performed via the branch and bound method and the reliability analysis is performed via the SQP algorithm. The next section demonstrates this methodology on an example problem.

4. EXAMPLE PROBLEM

The example problem presented illustrates the problem formulation developed in Sections 2 and 3. The problem corresponds to the illustration shown in Figure 1. The generator data are as follows:

x_i	Cost	PP_{ij}		
		Hospital	Fire	Police
1	25	N(50,2.5)	-	-
2	15	N(5,0.25)	N(10,0.5)	N(5,0.25)
3	10	-	N(5,0.25)	N(15,0.75)
4	20	N(10,0.5)	-	N(20,1)

Table 1: Generator Data

The demand data for the sectors are as follows:

Sector	PD_j	P_{crit_j}
Hospital	N(50,2.5)	0.9
Fire	N(10,0.5)	0.75
Police	N(10,0.5)	0.75

Table 2: Demand Data

It should be noted that all random variables are normally distributed with a coefficient of variation (COV = μ/σ) of 5%.

The electric grid generator settings were optimized using four configurations: optimum (where generator settings could take on any value between zero and one) and integer-only deterministic variables (evaluated at the mean values of the variables), and optimum and integer-only stochastic variables. The generator setting results from the example problems are shown below:

	Stochastic		Deterministic	
Generator	Optimum	Integer Only	Optimum	Integer Only
1	1.00	1.00	0.92	1.00
2	0.86	1.00	0.80	1.00
3	0.37	1.00	0.40	1.00
4	0.03	0.00	0.00	0.00

Table 3: Generator Setting Results

The cost results from the example problems are shown below in Table 4.

	Cost
Stochastic Optimum	42.11
Stochastic Integer	50.00
Deterministic Optimum	39.00
Deterministic Integer	50.00

Table 4: Cost Results

It is obvious that the integer-only solutions are more expensive than the equivalent optimum solutions. This is due to the fact that integer solutions represent power configurations that are providing the sectors with excess power. Additionally, it makes sense that the optimum value for the stochastic scenario costs more money (i.e. requires more power) than its equivalent deterministic scenario. This is because excess power must be provided to ensure that the required demand is met with the specified P_{crit}. The stochastic and deterministic integer solutions result in the same settings because they both provide a level of excess power that is adequate in both the deterministic and stochastic scenarios.

5. CONCLUSIONS

Utilizing a first order reliability method, this paper developed an efficient methodology for making power system decisions at the global level that incorporates the needs of local power system users. This methodology includes consideration of uncertainty in power demand and provided power.

Several extensions should be explored in future power system decision making methodologies. They include:

- **Nonlinear power functions.** Delivered power and demand require more complicated modeling than is present in this methodology. While this methodology is an appropriate starting point, realistic models should be incorporated using RBDO.
- **Non-linear and non-deterministic costs.** Cost is assumed to be both linear (increasing as d_i increases)

and deterministic. The effects of both non-linear and stochastic costs should be investigated.

- **More complicated sector interactions.** Sectors in this paper do not have a direct influence on one another as they would in realistic scenarios (i.e. as one sector is powered, the other has decreased power delivered). These interactions should be investigated further and a more complicated interaction model should be developed.

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Biography

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Prior to joining the faculty at Old Dominion University, he was a Graduate Student Researcher in the Security Systems Analysis Department at Sandia National Laboratories, where he worked on developing a methodology for safeguard resource allocation to defend critical infrastructures against a multiple adversary threat. Prior to that, he was a Project Engineer at National Steel and Shipbuilding Company in charge of Modeling and Simulation experiments to test shipboard logistics and cargo load-out capabilities. His research interests include multi-objective decision making under uncertainty, resource allocation, critical infrastructure protection, and network flows.

Resolving Intelligent Network Interoperability Challenges

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Abstract

Utility Intelligent Networks (UINs) are evolving from philosophy into reality. There are issues which seem to cause significant challenge as utilities adopt intelligent networks and their associated elements:

1. Many of the building blocks that comprise UIN are specified and acquired based on their primary function. While these systems will perform the basic functions well, they may be inadequate in serving some of the longer term intelligent network needs. It is important to establish an architectural view before the systems are specified.

2. The state of technology in each of these sub-areas impedes many of the sought after benefits. Utilities are implementing several next generation applications such as Outage Management Systems (OMS), Distribution Management Systems (DMS), Condition-Based Maintenance (CBM) and others in an effort to transform their operations. Many of these individual systems have the basics for effective interfacing, but achieving the integrated functionality from these systems requires substantial development and custom integration today.

This paper presents today's vital challenge areas associated with Interoperability. The paper highlights the relevant industry and standards activities underway that should lead to interoperability and suggests how lessons from present implementation experiences can be incorporated to ensure the desired interoperability and associated benefits. The paper also discusses an integrated architectural approach to developing UIN's initial specifications, intended to improve interoperability.

1. UTILITY INTELLIGENT NETWORKS (UIN)

Utility Intelligent Networks can be defined as networks having an increased awareness of the electric network and its ability to respond in real time, leading to better operational effectiveness for the utility and an improved experience for the customer. In short Utility Intelligent Networks represent the complete transformation of today's electric grid[1]. There are several industry drivers contributing to the need for a UIN:

- The asset base is aging. Several utilities are implementing large asset replacement programs and there is a recognition that we need to be smarter in implementing replacements.
- Load continues to grow and utilities are finding that they cannot respond by adding new generation.
- Increased pressure from environmentalists and state regulatory agencies' move towards Renewable Power Generator) RPGs and the need to reduce Green House Gas (GHG) emissions are changing the dynamics of adding new generation.
- Customers expect increasing levels of service. Utilities need to ensure their service at least matches, and perhaps surpasses the standards set by other industries.
- Our workforce is aging: It is anticipated that the industry could lose half its skilled workers in the next 5 to 10 years to retirement. The average age of line forces is also increasing, requiring changes to the tools crews use and the way they work.
- Technology costs continue to decline and performance of technologies available to deploy continue to improve.
- The industry is experiencing rising fuel costs. Further, it is believed that this trend will continue, along with potentially increasing volatility.

To respond to these drivers, a UIN helps a utility develop a new perspective for the future. Key aspects of this future include: (1) A combination of centralized and locally distributed generation sources that can economically provide energy; (2) Higher-quality materials that can transmit more power with fewer losses and failures; (3) Improved sensors that can instantly observe the state of the grid and transmit the information to multiple locations; (4) Improved remote control to provide control of the switches allowing for reconfiguring the network in real-time to minimize the extent of failures, or indicate maintenance requirements (5) An advanced network of integrated systems, both centralized and distributed, which can make intelligent decisions; and (6) More automated processes supported by trained people.

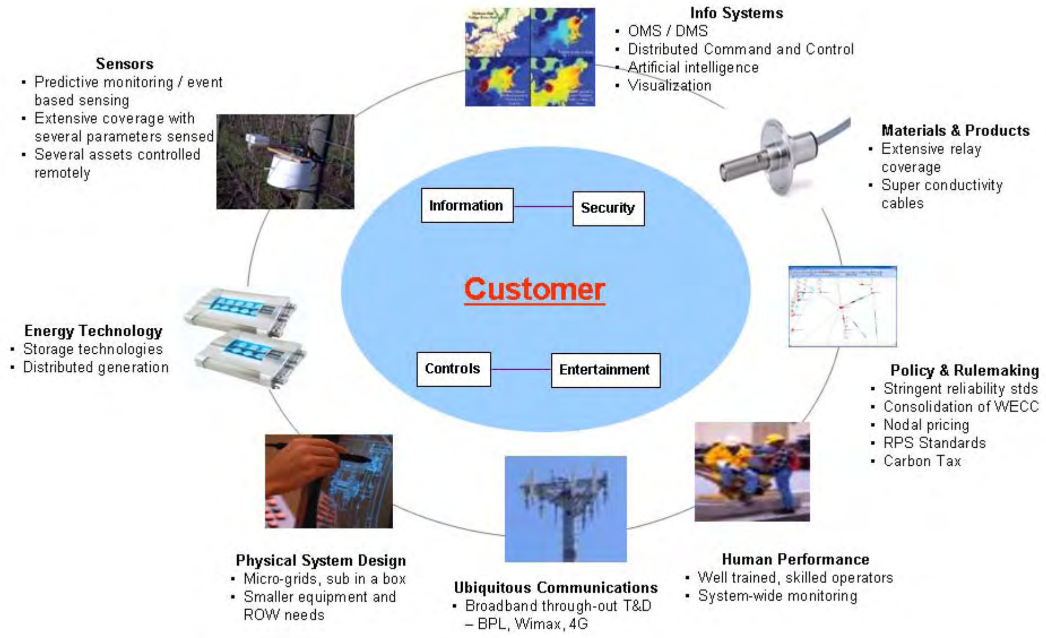

Figure 1 – Building Blocks for a UIN

While all of these components need to be considered, planning a system evolution can accommodate those that meet business objectives, and therefore all components are not needed from the beginning to construct a UIN.

Many of the systems and concepts required to implement UINs are in varying states of development. Utilities implementing intelligent networks today should plan for the subject technologies while investing in supporting integration and infrastructure.

"Interoperability" is a key aspect that needs to be considered as changes are being contemplated. In this paper, we focus on the following objectives:

- What does Interoperability mean?
- What are the challenges of Interoperability?
- What are the benefits of Interoperability?
- What avenues do utility practitioners have available to them to either learn about Interoperability issues or help influence the course of change?

1.1. What Does Interoperability Mean?

Interoperability has been defined as the ability of two or more systems or components to exchange information and to use the information that has been exchanged[2].

In the context of UINs, it means the following (not inclusive):

- Ability of smart meters to measure and communicate use and other relevant data across the enterprise.
- Ability of smart sensors to acquire diverse types of data and share it across the enterprise.
- Ability of software and engineering systems to "talk" and share data and functionality across an either centralized or distributed architecture.

Ultimately, interoperability will enable a new device to register itself in the grid upon installation; communicating its capabilities to its neighboring systems as well as having the connectivity database and control algorithms automatically update themselves upon the installation of the new device.

1.2. Interoperability Challenges

An element of information systems that tends to be taken for granted is the true catalyst behind enabling utility intelligent networks. Nearly twenty-one years ago, utility information technology experts and interested utility executives met to discuss how to better integrate the diverse emerging technologies replacing and augmenting the electromechanical systems of the day. The goal was interoperability, being able to integrate technology and systems more effectively and at lower cost. Much progress has been made over the last 20 years with three generations of "industry interoperability architectures[1]" evolving. Yet as new technologies are deployed, new challenges emerge.

[1] Utility Communications Architecture 1.0 (UCA 1.0), UCA 2.0 and the IntelliGrid Architecture

The recent growth of Advanced Metering Infrastructure implementations has accelerated interest in UIN as companies look to better leverage their investments in ubiquitous communications and inexpensive sensors. Companies see these systems as a subset of the building blocks that can form intelligent networks. However, the pioneers of implementing these technologies have identified additional interoperability needs. These needs are not unique. The same needs appear again as companies integrate additional sensors and systems, such as next generation SCADA, to their operational infrastructure.

1.2.1. Importance of an Architectural Perspective in Overcoming Potential "System Obsolescence"

Utilities are best served when they plan ahead to support desired functionality when installing building blocks intended to be used to form their UIN. This is not an easy process based on the state of current technology and the rapid changes underway in areas such as wireless communications. Further, this capability is complicated by lengthy installation times associated with systems such as AMI and new system operations applications, as well as that many of these applications do not map well to current utility organizational structures, creating potential unintended barriers to interoperability.

AMI systems present unique challenges when trying to plan for the future. Many utilities anticipate new and innovative rates. Many have the desire to obtain usage and related data in continually higher resolution. Few know exactly what will be the environment these systems are expected to support many years after they are installed.

Additionally, almost all AMI communications technologies deployed for "the last mile" today depend on proprietary routing protocols to efficiently utilize available bandwidth to minimize cost. While most of these products perform satisfactorily for their intended functions, many of them can be pushed to the point of failure when additional functions are added to support customer oriented functions such as demand response and smart house integration. In addition, not all AMI systems can support the near real-time requirements needed for utility intelligent networks.

Communications technologies can be deployed in a manner to support some of these higher bandwidth and response time requirements by installing a more robust communications infrastructure. For radio frequency based systems for example, this could mean the use of additional collectors, head-ends or the use of additional communications gateways and associated equipment. Typically, it is less expensive to account for the planned growth initially than it is to retrofit the infrastructure after installation has been completed.

While is it difficult to accurately forecast the need, and cost penalties are high for being overly conservative. A more robust communications system can be installed initially that will allow for the planned future functionality. Some of more successful tools which architecturally allow for future functionality are based on functional and communications requirements documented in the Utility Communications Architecture, Version 1.0[3] or through the concepts embedded in the IntelliGrid Architecture[4] documents. Based on these requirements, technologies and standards can be selected for implementation and integration that should allow for both future performance and enhanced interoperability.

Latency issues are a more difficult challenge to address. When latency issues are anticipated in future system expansion but details are uncertain, techniques such as expanding a wide Area Network (WAN) to parallel with portions of the "last mile" AMI communications technology can allow for maximum use of the initial AMI communications network, with an effective path to higher bandwidth and lower latency as requirements dictate and economics allow.

1.2.2. Application Interoperability Challenges

AMI systems usually use a more powerful interface to other operational and corporate applications than the traditional head-end systems that manage the communications with the end devices in the field for automated meter reading (AMR). While used in the wholesale market arena to manage interval data for many years, these new meter data management systems (MDMS) are in their relative infancy managing large AMI implementations, with only a handful or so installed supporting more than one million customer meters. Again, to maximize the benefits of AMI, the meter data and related events, alarms and data points should be shared in an interoperable fashion with other applications such as outage management systems, distribution management systems, distribution planning applications and load forecasting applications.

How the various meter data management systems interface with these other applications vary significantly from product to product. Some vendors offer the operational applications as extensions to the MDMS, based on their own interfacing techniques. Very few MDMS products have been implemented supporting the multiple integration products available today. Most vendors have limited integration experience with the diverse array of system operations applications in the field today, based in part on the relative newness of the MDMS concept.

A real-world example of this issue is one that utilities face when integrating the MDMS to their Operations Management System (OMS). Outage detection alarms can be caused by a variety of sources. Obviously an unexpected outage alarm is one that a utility would want to investigate. However, it is preferred that intentional outages for maintenance or switching operations not generate an outage alarm that is passed to the OMS as an alarm requiring action. Likewise, it is possible that millions of points could alarm in a very short period of time in a storm, creating a data overload and hampering the effectiveness of troubleshooting the actual electrical network problem(s).

Currently, there is limited standard filtering of alarms across the available MDMS applications. Passing the alarms from the MDMS directly to the OMS to handle can and has had disastrous effects. Many techniques have been deployed by vendors to make their products friendlier in this area, and utilities have actually deployed integration buses as filters between MDMS and OMS applications in an effort to improve interoperability.

As such, planning for the future state of a UIN before making such purchases and installations can greatly assist in maximizing the ability of what is installed to actually interoperate. Again, use of architectural design concepts to initially develop a technical architecture and resultant applications architecture can improve the details associated with the "future state" of the UIN.

1.2.3. Interoperability Challenges between Utility and Customer Premise Systems

A third looming area of interoperability challenges is now being embarked on by many utilities implementing demand response and attempting to integrate customer premise systems with distribution automation to optimize asset utilization, reliability and the like.

Specific support functionality doesn't exist in many of the AMI communications head-ends and MDMS systems available today. Most vendors will define Demand Response (DR) or in-premise functions as generic events and build a rule base around them in some instances. This will allow for the simplest functionality to occur. However, the lack of standardization as well as the limited functionality of the current product base will likely become a limiting factor in the near term growth of these systems. This is further complicated by the fact that the customer premise technologies can be deployed in a diverse array.

The concepts mentioned previously provides support to address this challenge as well. In addition, utilities should acquire and consider use of work sponsored by the California Energy Commission in developing a reference model that transcends a particular physical embodiment or use of a unique communications media at a customer premise. Combined with many of the business flows or "use cases" available from industry consortia to support interoperability in this area, a great deal of information is now available to work towards developing open interoperable systems to support these functions.

No common dictionary based on utility industry standards exists in this particular area to ensure a single data exchange format. When a new application that requires common information is implemented, interface development is complex and usually redundant. However, common data objects are shared repeatedly throughout the energy delivery lifecycle. This occurs through many different entry and exit points.

As such, this appears to be another opportunity to extend the IEC TC 57 WG14 Common Information Model (CIM). Since CIM is a static information model that represents all data that can be exchanged between applications, it would seem to be the ideal tool to assist in developing methodologies to address the interoperability issues. In addition, the latest ANSI C12.19 and C12.22 work within smart meters holds promise to standardize the way applications would access and operate on meter data. In addition, UCA 2.0 (IEC 61850) also offers capability to exchange unambiguous data in real time. A harmonization of these efforts would yield a significant advance in interoperability.

1.3. Why is Interoperability Important?

Interoperability provides many benefits, in addition to facilitating the UIN. Implemented correctly, interoperability can significantly reduce integration costs in addition to reducing staff training and maintenance costs. Applied in the UIN paradigm, more interoperable systems benefit end users by facilitating efficiency, simplifying the interconnection of distributed resources and enabling demand response. Further, it facilitates multiple concepts to be combined to achieve functionality we cannot easily implement today.

Some examples of functions not easily implemented today involve the ability to build a non-hierarchical asset knowledge base utilizing distributed System Control and Data Acquisition (SCADA). Another capability enabled by intelligent networks is the modification of SCADA settings on the fly to accommodate changes in local situations.

In a more futuristic scenario, a UIN will enable an incipient fault to be detected and located before significant damage occurs. This will enable the intelligent network to perform multiple actions in parallel upon locating the incipient fault, including the ability to:

- Reconfigure the flow of electricity to minimize the size of the outage due to the fault in a quarter of a cycle
- Isolate sensitive customers in the area by switching to local distributed resources or electronically switching

them to a different source of supply in a quarter of a cycle

- Operate power electronic equipment to manage the real (voltage) / reactive(VAR) power balance and to activate local generation (or utilized storage) as needed in the area to provide for safety and stability of the system
- Implement direct load control as-needed
- Send price signals, or adjust other similar instruments allowed by creative tariffs, to alter the pattern of use until the problem is resolved
- Modify real-time protection settings to utilize assets in an emergency mode and provide automatic operational updates for maintenance intervals, and other important triggers
- Alert local stakeholders to the nature of an event, the actions taken and the plan for restoring normal operation.

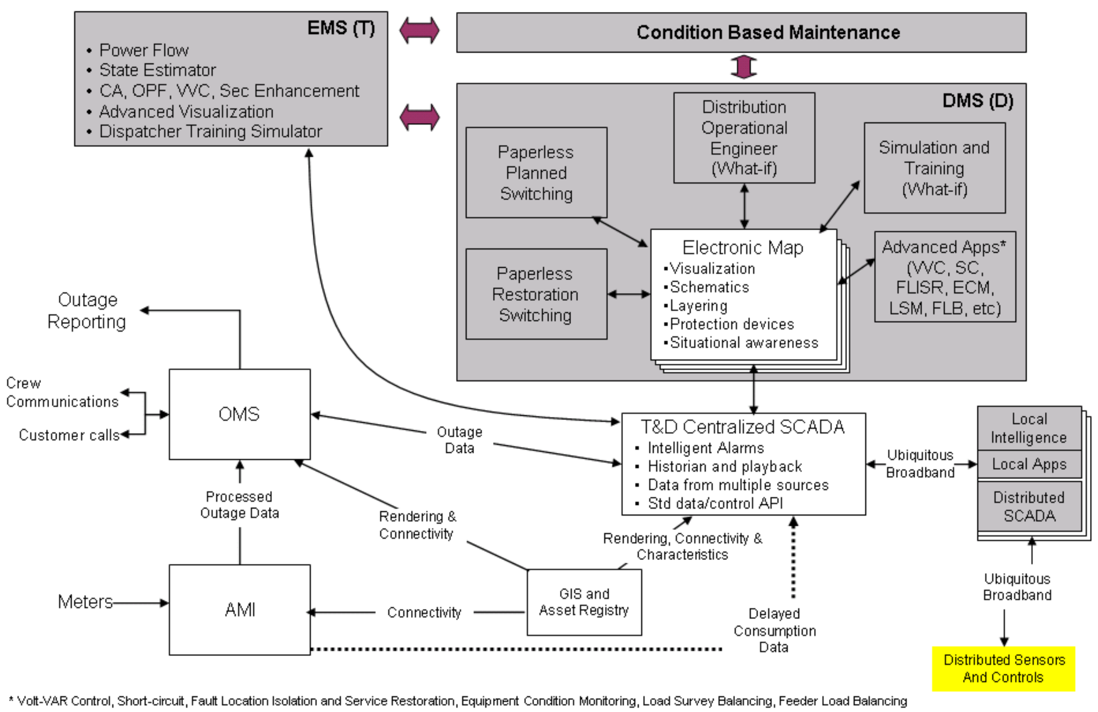

Figure 2 – Representative Applications Architecture

1.4. Summary and Looking Forward

Since the first call to action, the past twenty years has seen tremendous progress in how the industry has worked together to address the issues associated with interoperability. ANSI, EPRI, the various GridWise organizations, IEC, IEEE, NRECA and others, augmented by emerging industry consortia, have created both the knowledge base to draw from and an initial set of standards and models the industry can implement. CIM, IntelliGrid Architecture, MultiSpeak, TASE-2, UCA, and the oversight guidance and GridWise Architecture Council concepts all contain valuable knowledge to assist utilities and integrators in achieving interoperability.

For now, use of planning concepts and tools developed through open systems architecture development along with traditional systems integration techniques will help allow one to overcome many of the remaining challenges that exist today to allow a UIN to seamlessly interoperate.

Industry support for continued development in several areas could significantly improve the potential state of interoperability, thereby improving the cost-benefit ratio of deploying a UIN. Specifically:

- Continued CIM related development and standardization for distribution and as applicable, to and within the customer premise
- Additional support for customer premise "reference designs" that enable systems to be developed to support intended functionality without specific knowledge of the physical embodiment of the customer premise technology.

More broadly and looking forward, more cooperation through industry consortia such as OpenAMI and others will be key to move these open systems specifications and standards into "implementers agreements" to ensure the interoperability utilities desire.

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Biography

Mark G. Lauby joined the North American Electric Reliability Corporation (NERC) in January 2007 as the Manager of Reliability Assessments. Mr. Lauby leads the electric reliability organization's efforts to independently assess and report on the overall reliability, adequacy, and associated risks of the interconnected North American bulk power system.

Prior to joining NERC, Mr. Lauby worked for the Electric Power Research Institute (EPRI) since 1987 where he held a number of senior positions, including: Director, Power Delivery & Markets; Managing Director, Asia, EPRI International; and Manager, Power System Engineering in the Power System Planning and Operations Program. Mr. Lauby started his career in the electric industry at the Mid-Continent Area Power Pool (MAPP), in Minneapolis, Minnesota in 1979. His responsibilities included transmission planning, power system reliability assessment, and probabilistic evaluation.

Mr. Lauby earned both his Bachelor of Electrical Engineering in 1980 and his Master of Science in Electrical Engineering in 1989 from the University of Minnesota.

He is the author of over 100 papers on the subjects of power system reliability, expert systems, transmission system planning, and power system numerical analysis techniques. Mr. Lauby is past Chair of the International Electricity Research Exchange (IERE), is a Senior Member of the Institute of Electrical and Electronic Engineers (IEEE), and served as Chairman of a number of IEEE working groups. Mr. Lauby has been recognized for his technical achievements in many technical associations, including the 1992 IEEE Walter Fee Young Engineer of the Year Award.

Wade P. Malcolm, P.E. joined Accenture as a Senior Manager in the System Operations Practice Area in February, 2007. Mr. Malcolm is actively involved in a number of intelligent networks and advanced metering initiatives.

Mr. Malcolm has nearly 25 years of experience involving consulting, technology development and delivery, and utility operations. Mr. Malcolm has a broad background with substantial experience in utility information systems, distribution, customer interface, metering, and communications technologies. He is a former officer of the Electric Power Research Institute (EPRI), Powel Group, Inc. (now Powel ASA), UTILITY.COM, a former executive of SRI Consulting (formerly the Stanford Research Institute) and was previously employed by Exelon/PECO Energy. He has consulted to several utilities and has also provided energy-related consulting to both customers and vendors of utilities. Mr. Malcolm is a Senior Member of the IEEE and is a Registered Professional Engineer in the Commonwealth of Pennsylvania.

Mr. Malcolm earned both his Bachelor of Science in Electrical Engineering in 1982 and his Master of Science in Electrical Engineering in 1984 from Drexel University.

Mani Vadari, PhD is a partner at Accenture and leads the Network Management Practice.

Dr. Vadari is a Partner in Accenture and leads the Network Management area within the T&D practice. In this role, he focuses on Transmission and Distribution Operations, Outage Management, and Intelligent Networks. He has almost 20 years of experience delivering strategic solutions to the electric utility market focusing in areas such as Transmission/Distribution Grid Operations, Generation Operations, Energy Markets, and RTO/ISO market participants. His extensive experience spans the regulated as well as unregulated arena for utilities and energy companies.

Dr. Vadari has been with Accenture since April 1997. His roles primary have been as an architect focusing on designing the right technology, processes and organizational impacts for many leading utilities in the country and around the world. He has also provided subject matter expertise in setting the strategic technical direction for developing key aspects of the Transmission/Distribution grid of the future.

Dr. Vadari has authored over 25 papers in a variety of areas from Dispatcher Training Simulators to artificial neural networks to electricity utility deregulation.

"Duke Energy's Utility of The Future: Developing A Smart Grid Regulatory Strategy Across Multi-State Jurisdictions"

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Abstract

An overview of the regulatory challenges faced by Duke Energy as it pursues its Utility of the Future project.

Duke Energy (NYSE: DUK) is one of North America's largest electric power companies. Headquartered in Charlotte, NC, it has nearly 37,000 MW of generating capacity (plus 4,000 MW more in Latin America) and serves nearly 4M customers.

Duke Energy's long term vision is to transform the operation of its electric power grid by creating a reliable and scalable networked infrastructure capable of delivering and receiving information from intelligent devices distributed across its power systems, automating components of the distribution systems and leveraging the linked networks for improved operational efficiencies and customer satisfaction. Duke Energy refers to this new networked infrastructure as its Utility of the Future (UoF) project.

KEMA, Inc. has been onsite with Duke since the inception of the UoF project, and continues to serve as Duke's external counsel regarding project implementation.

Article

Duke Energy's initial Smart Grid pilots are already underway as it seeks to fine-tune its network configuration for various topographies (urban, suburban, rural). Two examples include:

1. **Piloting advanced metering and distribution automation** in Charlotte to test potential communications systems, distribution sensors, meters and in-home applications

2. **Integrating non-BPL communications and multiple meter types** in Bloomington, IN to create a Smart Grid "testbed" and to serve a varied customer base that includes industrial, commercial, urban, rural and large campuses

Duke Energy's full-scale Smart Grid rollout will begin in the second half of 2008 and continue for several years.

At present, Duke is preparing to execute a number of development initiatives across its jurisdictions. Phase I deployments of the UoF project will include the installation of hardware and software necessary to create a communications network infrastructure. The infrastructure will enable a subset of the future business opportunities described within the project description statement to support specific customer locations as follows:

- Charlotte, NC
- Greenville, SC
- Cincinnati, OH

1. DUKE ENERGY'S UTILITY OF THE FUTURE PROJECT

1.1. Overview

Duke Energy's long term vision is to transform the operation of our electric power grid by creating a reliable and scalable networked infrastructure capable of delivering and receiving information from intelligent devices distributed across our power systems, automating components of the distribution systems and leveraging the linked networks for improved operational efficiencies and customer satisfaction. This new networked infrastructure will provide the future platform for changing the customer experience and their use of energy in support of Duke's Energy Efficiency program.

1.1. Detailed Description of the Project

The primary focus of this project is to analyze, design and deploy a portfolio new communication networks to service specific customer areas within the Carolinas and the Midwest. This network will use our electric distribution power lines/grid to link intelligent devices such as meters, data aggregators, transformers, and substation devices in a networked fashion. Via the network, these devices will send and receive data to various utility systems for the purpose of improving operational efficiencies and customer satisfaction.

The communications network foundation to be implemented under the Utility of the Future initiative will begin to provide technical capabilities required to support Duke's Energy Efficiency Save – A – Watt approach as a Fifth Fuel. Future data received from intelligent devices across our distribution system will be available for enabling the Energy Efficiency Program and other enterprise software applications which will measure, protect and automate Duke's electric grid creating future opportunities and benefits for Duke Energy and its customers in the following areas:

Opportunity	Benefit
Advanced Metering	AMI, more efficient move in/out processes, remote connect/disconnect of service, billing exceptions, reduction in billing cycle, improved meter accuracy, revenue protection, load research
Energy Efficiency	Demand Side Management (DSM) program proliferation, operational efficiencies, value of load to operations, value of energy in the market
Distribution Automation	Volt / VAR control & management, asset management, power quality driven O&M
Outage Management	Detection and verification, revenue impacts
Call Center	Reduction in overall call volume related to meters, trouble calls, change in service and billing
Substation Automation	Asset management
Environmental	Reduction in CO_2 from reduced truck rolls

Societal	Customer opportunity cost due to outages

In addition, the project will identify and resolve any operational, technical, regulatory, or vendor issues pertaining to network infrastructure deployments. Additional deployment costs or benefits not already identified in the business case will be identified and assessed from actual performance within service areas where new network assets are deployed. Information gathered from deploying these new assets will provide verification of business case assumptions, and will be used as input to future deployment initiatives beyond this project.

Duke Energy's plan begins with the installation of smart meters and communications. Advanced metering will be an initial application, which can also include utility benefits such as improved outage detection and response. From there, Duke Energy expects to add system optimization correlating data to allow us to fine-tune voltages and reactive power and optimize on a feeder-by-feeder basis, so we don't overbuild. Eventually, Duke will begin to experiment with microgrids.

Before deploying new network infrastructure assets within a service area, system testing will be conducted. Metrics from system testing will be collected and analyzed to confirm that network infrastructure, new system functionality and system data integrity are implemented and working per requirements. System testing will determine the relative efficiency and reliability of different configurations of networked devices deployed across our various topographies, system configurations and technical/regulatory operating requirements.

2. Regulatory Cost Recovery

2.1 General Observations on AMI / Smart Grid Cost Recovery

For any utility pursuing an AMI project, cost recovery is a major concern. Utilities may face a number of regulatory challenges in their efforts to secure cost recovery for AMI / Smart Grid projects, including demonstration of positive net benefits of the project; cost allocation issues; underappreciated existing meter costs; and negative or non-supportive commission views on smart grid technology**.**

Based on findings from a study that KEMA conducted earlier this year, the average cost for an AMI / Smart Grid utility project is approximately $775 million. While the costs of the project may be easy to quantify on the front end, the long-term benefits of technology improvements may not be as clear to regulators, particularly since the benefits may be spread over multiple customer classes and may not be fully realized for years. The unfortunate result is that state regulators may be reticent to approve cost recovery or even the implementation of AMI / Smart Grid technologies without specific guarantees that benefits of the technologies will exceed the costs in the long-term. It is a challenge for all utilities that are including technology upgrades in their future business plans.

The way regulators add up the costs and provide rate recovery for AMI / Smart Grid investments will largely determine how utilities and their shareholders perceive AMI investments. A public utility commission might easily justify rate-basing capital costs for new metering hardware, but less certain is how a utility should bear the costs of retooling its internal processes to pursue the Smart Grid vision, as well as marketing the new program and educating customers to ensure maximum benefits continue flowing.

In data gathered on AMI / Smart Grid cost recovery means, some common trends among the approaches that utilities and public utility commissions are taking began to emerge. In fact, cost recovery strategy appears to fall into one of the following categories, regardless of the state jurisdiction:

- Trackers: A mechanism that follows or "tracks" unpredictable costs that the utility incurs. Typically, trackers are determined at the end of the year and then recovered over a 12-month period. Trackers can be both targeted to a specific project, or have a broader distribution (i.e., address aging infrastructure too).
- Balancing Accounts / Rate Base: A balancing account is an accounting procedure developed by the governing utility commission to track and recover reasonable and prudent costs unrecovered through retail bills due to the application of applicable rate freezes or ceilings. The rate base of a utility is established by governing utility commission. It determines the value of the physical assets of the utility which are used to provide services and can be recovered from customers in rate structures.
- Customer Surcharge: A mechanism that has no standard statutory definition, but typically is a charge defined by the governing utility commission and imposed on customers to recover utility expenses.

- State Funding: It varies state-by-state, but this approach includes funding for projects provided from existing or newly created state accounts.
- None; Instances in which no cost recovery plan has yet been developed for an AMI / Smart Grid project.

In the United States, the regulatory landscape is Landscape is generally positive for AMI / Smart Grid cost recovery. No state has denied outright cost recovery of an AMI project, although applications are pending in several states. The most common recovery methods are trackers and building recovery into rate base.

Of these options, trackers appear to represent the most common trend, as they offer a good manner for focused cost recovery, in absence of going through the full rate case process. They also appear to be attractive given the uncertainty surrounding estimates of total project costs. Trackers presumably save time and limit the risk exposure for the utility.

The second most common approach is to approach cost recovery through surcharges. Most utilities appear to be taking a marginal-costs approach when proposing either a surcharge or rate base recovery option. In other words, most utilities appear to be arguing that the determination of a class' customer-related distribution cost responsibility based on estimates of marginal customers costs (costs to serve that class) multiplied by the number of customers the class.

Other options used for AMI / Smart Grid cost recovery, although not as common as the ones listed above, include the following:

- DSM Tracker
- Earnings sharing mechanism
- Participant fees
- Deferred accounting
- Formula rates
- Combinations of some of the above

2.2. Unique Regulatory Challenges Faced By Duke Energy

As mentioned above Duke Energy has utility operations in five states and is presently planning initial deployment of its Utility of the Future project in three deployment locations. None of the three states in which Duke Energy is planning these initial deployments (North Carolina, South Carolina, and Ohio) has formalized any cost recovery policy for AMI / Smart Grid cost recovery.

Ohio is making the most traction toward developing a cost recovery policy. The Public Utilities Commission of Ohio (PUCO) is holding a series of workshops related to AMI / Smart Grids (Case No. 07-646-EL-UNC). Along with two broad policy presentations related to the benefits of AMI, the workshops will also address cost recovery via discussions of the financial model to used for regulatory filings in the state. The workshops intended to provide stakeholder feedback to inform PUCO Staff recommendations to the PUCO for a decision. Timing of the proceeding beyond the workshops is not scoped.

What appears likely is that the PUCO staff will default to use of the McKinsey Model, but is open to conducting off-line discussions on alternatives. All electric distribution companies and PUCO Staff must be in agreement if a model other than McKinsey is utilized.

Duke Energy--Ohio (DEO) is planning to file an application with the PUCO seeking an increase of $34 million, or 5.8 percent overall, in natural gas rates. The increase would be effective in the early- to mid-2008. In this filing, DEO will seek approval to make annual rate updates to recover the cost of the new equipment. This filing, part of Duke's general rate case in Ohio, is separate from what will be likely be separate regulatory filings focused exclusively on the Utility of the Future project (not just in Ohio, but in all of Duke's five states of operation).

Duke Energy's overall regulatory strategy for its Utility of the Future projects includes the following prioritized objectives:

- Prioritize States based on the following criteria:
    - Regulatory receptivity to smart grid technology
    - Regulatory receptivity to timely cost recovery
    - Existing unrecovered / underappreciated sunk meter costs
    - Consider expanding U of F to encompass aging distribution infrastructure improvements
- Communicate vision, costs and benefits to regulators
    - Develop compelling "road show" for regulators to educate them on the Utility of the Future objectives.

  - Meet with key stakeholders
  - Create and implement demonstration labs
- Implement initial deployments
- Develop strategy to transition to installation of new technology meters.

Before proceeding with the deployment in any state, Duke Energy has established a methodical approach to enable favorable regulatory strategy in that particular jurisdiction. Before proceeding in any state: First, the company plans to educate regulators and other stakeholders about its vision and the benefits and costs of implementing Utility of the Future. Toward that objective, Duke intends to create a compelling "road show" that gets people excited about the possibilities and eager for initial deployments. Duke also intends to complete a Demonstration Lab that will simulate various processes supported by the project and plans to coordinate strategic fieldtrips with key stakeholders. The second step Duke intends to take in each state is to develop regulatory proposals that are most appropriate for each jurisdiction. Third, Duke will develop detailed cost/benefit analyses of U of F / aging infrastructure proposals. And fourth, Duke Energy will continue with proof of the U of F concept through initial deployments.

Duke Energy also has developed specific regulatory strategies for the three states in which it is pursuing initial deployment of its Utility of the Future project. The state-specific regulatory strategy has been outlined as follows:

North and South Carolina:

- Explore broader Utility of the Future concept, encompassing aging distribution infrastructure improvements
- Consider Utility of the Future stand-alone tracker filing, or rate case/tracker filing, in 2009
- Bottom line: pursue Utility of the Future regulatory filing in 200

Ohio:

- Participate in PUCO's smart metering workshop (now through Dec. 07).
- Continue to push for implementation of U of F tracker in current gas rate case.
- Depending on outcome of PUCO smart metering workshops, propose stand-alone U of F tracker for electric (alternatively, could propose U of F tracker in electric rate case planned for Ohio in 2009).
- Utility of the Future rate case filing (electric) in 2008 or 2009.

At this time (October 2007) does not have exact cost figures for the various pilot projects, but as decisions are made it will seek regulatory recovery of the costs. By the end of the first quarter 2008, the initial deployments should be under way.

Biographies

Charlotte, NC-based Duke Energy serves approximately 3.9 million customers in five states: North Carolina, South Carolina, Ohio, Indiana, and Kentucky. Established in 1927, KEMA Inc. is an international, expertise-based energy solutions firm providing technical and management consulting, systems integration and training services to more than 500 electric industry clients in 70 countries. There are a number of regulatory challenges that Duke Energy presently faces related to its Utility of the Future project, not the least of which is the fact that it must eventually submit regulatory filings for the project to five different public utility commissions.

KEMA has been serving the complete spectrum of participants in the energy marketplace for over 30 years and offers a full complement of services supporting generation through the customer meter.

Mr. Will McNamara, Principal Consultant at KEMA, is a regulatory and legislative affairs expert with 15 years of energy industry policy-making, rate design, expert testimony, and lobbying experience. Mr. McNamara has unique expertise in developing AMI policy and managing business plans and regulatory filings within the areas of energy efficiency, demand response, and smart grids. He presently serves as project manager providing support to Duke Energy's Utility of the Future Project, in which the utility is preparing to execute a full-scale AMI deployment across its multi-state service territory. In this role, Mr. McNamara has overseen the creation of Duke's use cases and functional requirements for its planned AMI system, technology vendor selection, and development of its regulatory business case and cost-recovery proceedings. Prior to joining KEMA, Mr. McNamara managed legislative and regulatory policy for Sempra Energy, during which time he was helped develop the company's AMI business strategy and approved all of the California regulatory filings of San Diego Gas & Electric's AMI business plan and cost recovery strategy. He has appeared as an expert witness and provided testimony in numerous hearings before the California Public Utilities Commission; the California Energy Commission; the California Senate and Assembly; and the Federal Energy Regulatory Commission. In his work as an energy consultant he has also managed regulatory filings on behalf of utility clients in the states of Arizona, New Mexico, and Colorado. Mr. McNamara holds an MBA, M.A. in Mass Communications and a B.A. in political science / journalism.

Mr. Matt Smith is Director of Technology Development and the Utility of the Future project for Duke Energy. He was named to his current position in October 2006.

Most recently, Mr. Smith worked in strategic planning for Duke Energy. Prior to the merger between Duke Energy and Cinergy, he worked in mergers and acquisitions and strategy for Cinergy. While at Cinergy, he also worked in Cinergy Solutions and in Cinergy's merchant business unit in a policy role.

Mr. Smith earned a bachelor of arts degree in business administration from Weber State University in Ogden, Utah. He earned a JD/MBA from the University of Kentucky College of Law and Gatton College of Business in Lexington, Kentucky.