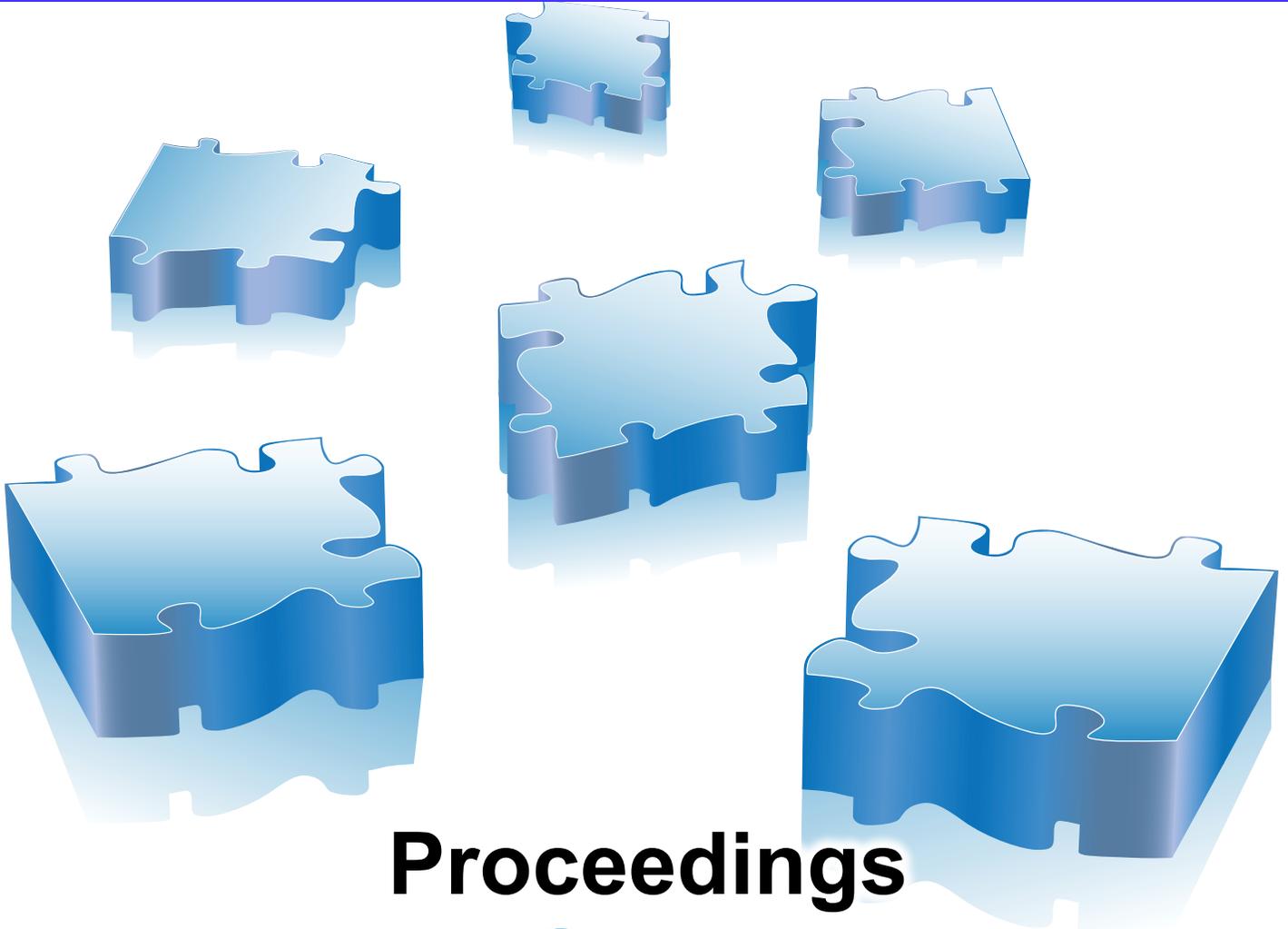




*Ensuring Smart Grid Interoperability*



# Proceedings

**Atlanta, GA**

**November 11-13, 2008**



# THANK YOU FROM THE TEAM

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January 6, 2009

Grid-Interop Participants and Interested Colleagues:

Advancing interoperability for a smart grid is about making connections easier and more reliable. That requires a community of stakeholders with an appreciation of complex system integration issues to share their views and develop unifying directions. The 210 registered attendees of the second Grid-Interop Forum provided valuable information to NIST in their coordination efforts to develop an interoperability framework for the smart grid and support for the Domain Expert Working Groups (DEWGs). They also listened to an inspiring set of plenary speakers who emphasized the importance and urgency of resolving interoperability issues. They interacted with informed, thought-provoking presenters in 15 panel sessions that covered technical, architectural, and business and policy topics related to interoperability. We are pleased to make the following proceedings from Grid-Interop 08 available to these participants and to those interested parties who were unable to attend.

This record of the event 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 NIST workshop sessions with links to the full report. These sessions produced many good ideas for advancing interoperability that will require our continued interaction.

Our sincere thanks go to the event sponsors whose support made this meeting possible and to the many volunteers, authors, speakers, and organizers whose hard work and commitment was responsible for the high quality of the sessions. As with the first Grid-Interop, we were amazed at the excellent level of interaction between participants during meals and breaks. The diversity of backgrounds provided a rich set of perspectives that are necessary to understand and reconcile as we move forward.

Now our efforts begin for planning Grid-Interop 09. More information will be available about that soon. We hope to see you at that event and encourage your participation in the on-going work of NIST, the GWAC, and the DEWGs.

Kind regards,



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Interoperability Framework Lead, NIST



Jack Mc Gowan  
GWAC Chair



Steve Widergren  
GWAC Administrator

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## IMPORTANT LINKS

**Grid-Interop**

<http://www.grid-interop.com>

**GridWise Architecture Council**

<http://gridwiseac.org>

**National Institute of Standards and Technology**

<http://www.nist.gov/smartgrid/>

**Pacific Northwest National Laboratory**

<http://www.pnl.gov>

**DOE EERE**

<http://www.energy.gov/energyefficiency/index.htm>

## Contents

Thank You From the Team .....	i
GridWise Architecture Council Members .....	ii
NIST Interoperability Framework Team .....	ii
GWAC Administration.....	ii
Important Links.....	ii
Introduction.....	1
Keynote Speakers .....	2
Foundational Session.....	2
Interactive Interoperability .....	2
Reference Documents.....	3
Whitepapers .....	3
Proceedings .....	3
Reports.....	3
Architecture Track .....	4
Business & Policy Track.....	5
Technology Track.....	5
Closing Plenary .....	5
Recognized Papers: .....	5
Appendix A. Agenda.....	6
Tuesday, November 11, 2008 .....	6
Wednesday, November 12, 2008 .....	7
Thursday, November 13, 2008 .....	7
Appendix B: Forum Participants.....	8
Appendix C: Papers .....	17

## INTRODUCTION

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Grid-Interop 2008 was the second annual meeting addressing technical, business and policy concerns related to developing an interactive electric system that allows all resources to participate in its effective operation. With the passage of the Energy Independence Security Act (EISA) of 2007, in early 2008 the National Institute of Standards and Technology (NIST) was assigned responsibility for developing a standards based interoperability framework in support of smart grid implementation. An important objective of the GridWise Architecture Council has been to support NIST in this effort. Accordingly, the GridWise Architecture Council (GWAC) and NIST jointly sponsored Grid-Interop 2008.

Planning for the meeting was carried out by a joint GWAC / NIST committee. The committee rose to the challenge of formulating an agenda that would build on the positive results of the previous year's meeting and at the same time help NIST achieve its mandate under the EISA. The committee consisted of Joe Bucciero, Anto Budiardjo, Alan Cookson, Rik Drummond, Jerry FitzPatrick, Dave Hardin, David Holmberg, Ron Jarnagin, Ron Melton, and Steve Widergren. The committee defined two major areas of activity that bridged the interactive panel sessions initiated the previous year with facilitated workshops to elicit directions and gather input for NIST's efforts.

First, the NIST Domain Expert Working Groups in Transmission and Distribution, Home to Grid, Industry to Grid and Buildings to Grid met to assess the current state of interoperability standards in their respective areas. Workshop sessions also focused on Security and Business & Policy concerns. Each of the Domain Expert Working Groups held facilitated workshop sessions to capture and document information needed by NIST in preparing their first EISA report to the U.S. Congress and in planning future activities. A summary of the workshop results is included in these proceeding and a link to the full results is provided.

The second major activity was the panel sessions. As was the case last year, there were many excellent responses to the call for papers. The resulting presentations were organized into three tracks: Architecture, Technology, and Business and Policy. There were approximately 58 presentations within the three tracks. Links to these presentations are provided in the following pages of these proceedings.

In addition to the presentations 28 written papers were accepted for publication. The authors were asked to focus specifically on interoperability as it related to the overall topic of their paper. These papers form an important body of knowledge for the community to refer to as work on developing and implementing an interoperable smart grid proceeds. Links to the papers are provided in an appendix to these proceedings. One paper from each track was selected for recognition for both content, clarity of writing, and relevance to interoperability.

Finally, Grid-Interop 2008 was again fortunate to have several distinguished speakers. The speakers provided important context and guidance for both NIST in their efforts to develop the interoperability framework and for the discussions in the question / answer portions of the panel sessions. The keynote, lunch and dinner speakers are listed in the following section along with the recognized papers.

## KEYNOTE SPEAKERS

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[View Presentations](#)

**Gordon van Welie**

President & CEO, ISO New England Inc.

**Fredrick Butler**

Commissioner and NARUC Chair  
New Jersey Board of Public Utilities

**Suedeem G. Kelly**

Commissioner, Federal Energy Regulatory Commission

## FOUNDATIONAL SESSION

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[View Presentation](#)

The 2007 Energy Independence and Security Act (EISA) gave NIST the mandate to coordinate an interoperability framework for the Smart Grid (SG) based on model standards and protocols. When consensus has been achieved by the Smart Grid stakeholder community, NIST is to recommend standards to the Federal Energy Regulatory Commission for adoption.

NIST is creating a Smart Grid Standards Knowledge Base (SKB) and roadmap to achieve interoperability among Smart Grid applications as part of NIST's EISA role. Working groups comprising experts in four SG domains, and co-chaired by NIST and Gridwise Architecture Council (GWAC) have been established to provide input to the SKB and roadmap:

Building-to-Grid (B2G), Industrial-to-Grid (I2G), Home-to-Grid (H2G), and Transmission and Distribution (T&D). In addition, a fifth working group, the Business & Policy (B&P) Working Group, was established to examine SG business and regulatory issues and coordinate with the other groups.

The Foundational Session presented the purpose and expected outcomes of the Workshop Breakout Sessions in the context of the mandates of EISA 2007. An overview of the NIST EISA mandate, the NIST program, Workshop objectives and plan, was presented as well as some key definitions and progress of the DEWGs in creating the way forward to achieving Smart Grid interoperability.

**Jerry FitzPatrick**

Leader, Applied Electrical Metrology Group, NIST

**David Holmberg**

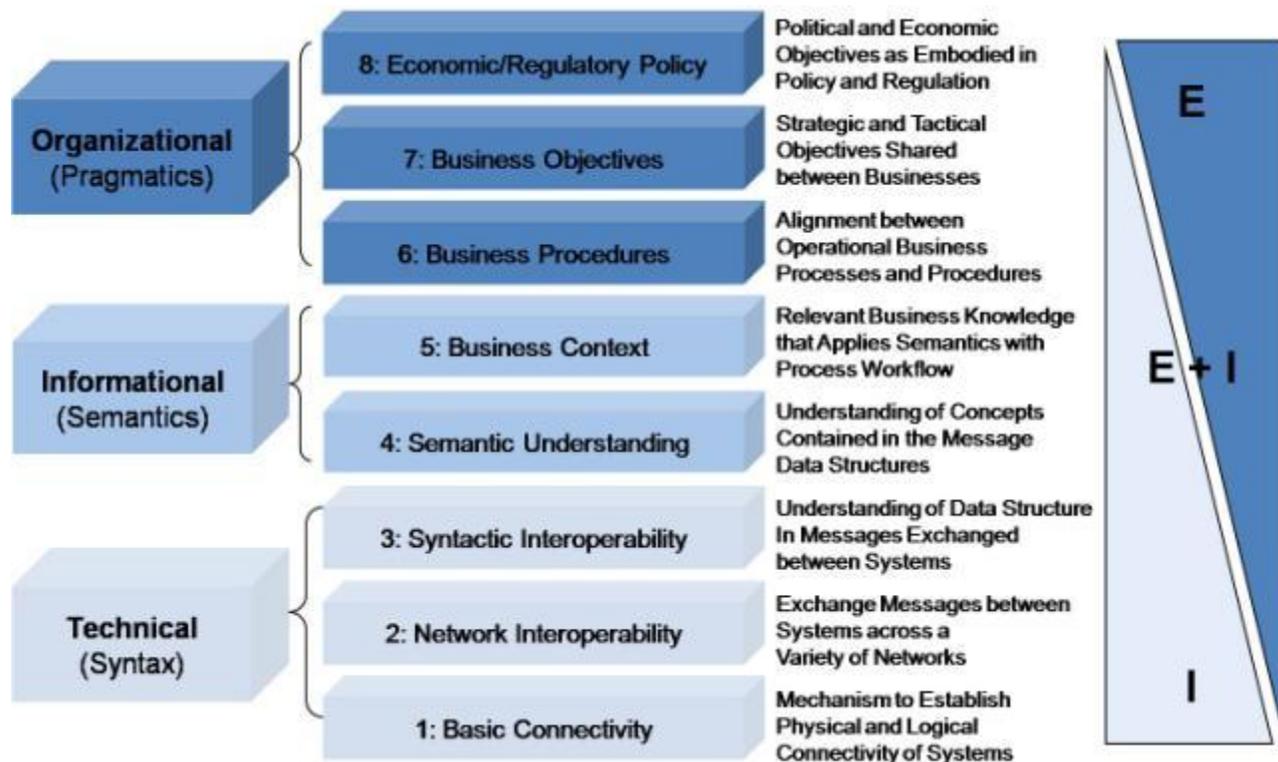
BACnet Utility Integration Workgroup Lead, NIST/BACnet

## INTERACTIVE INTEROPERABILITY

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A key objective of Grid-Interop is the development of the Smart Grid community, especially those involved with the evolution of technologies, methodologies and best practices relevant to interoperability. For the second year, an important session to further this objective was the

engagement activity, a serious but light hearted way to look at a key component of the interoperability framework; the GridWise Architecture Council Framework Stack:



## REFERENCE DOCUMENTS

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### WHITEPAPERS

- Decision Maker's Checklist ([PDF 153KB](#))
- Interoperability Context-Setting Framework (v1.1) Document ([PDF 805KB](#))
- Interoperability Path Forward Whitepaper ([PDF 77KB](#))
- Interoperability Constitution Whitepaper ([PDF 67KB](#))
- GridWise Architecture Tenets and Illustrations ([PDF 271KB](#))

### PROCEEDINGS

- Grid-Interop 2007 ([PDF 7,765KB](#))
- Interoperability Workshop ([PDF 550KB](#))
- Constitutional Convention ([PDF 1734KB](#))

### REPORTS

- GWAC Summary of Constitution Interview Process and Feedback ([PDF 2249KB](#))

# NIST WORKSHOP

The Energy Independence and Security Act of 2007 (EISA) calls for the National Institute of Standards and Technology (NIST) to coordinate the development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems. On November 11-13, 2008, NIST, the U.S. Department of Energy (DOE), and the Grid Wise Architecture Council organized a series of breakout sessions as part of the Grid-Interop 2008 conference to engage stakeholders in its plan to develop the framework. More than 190 experts from standards developing organizations, utilities, equipment manufacturers, state agencies, trade associations, and national laboratories attended. The goal was to explore and advance the nature of the interoperability framework.

NIST, in an effort to engage a wide stakeholder base in the development of the framework, has formed five Domain Expert Working Groups (DEWGs). The workshop included six parallel breakout sessions based on the working groups and cyber security, a concern of all the DEWGs. The DEWGs are based on the electric grid and its interfaces to electricity consumers in the smart grid. The largest DEWG, Transmission and Distribution (T&D), includes representatives from the Federal Energy Regulatory Commission (FERC), Independent System Operators, the Institute of Electrical and Electronics Engineers (IEEE), the Electric Power Research Institute (EPRI), Utility Trade Associations and the T&D community at large. The next three DEWGs, Building to Grid (B2G), Home to Grid (H2G), and Industrial to Grid (I2G) focus on electricity exchanges within the electric grid. The Business & Policy (B&P) DEWG addresses issues related to the regulatory environment as well as legislative and business decision-makers. The Cyber Security (CS) area addresses security concerns relevant to all the other DEWGs.

The workshop results will be available for download at the [GWAC website](#) or the [NIST Smart Grid website](#).

## TRACK SESSIONS

### ARCHITECTURE TRACK

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[View Presentations](#)

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.

## BUSINESS & POLICY TRACK

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### [View Presentations](#)

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.

## TECHNOLOGY TRACK

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### [View Presentations](#)

The technology track focused on the technical issues of implementing interoperable smart grid systems. The panels addressed how interoperability concepts and architectures have been implemented through the application of specific standards, technologies, devices and best practices. Case studies were presented that illustrated how interoperability was achieved through the application of technologies and best practices from other industries.

## CLOSING PLENARY

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### [View Presentations](#)

#### **David Holmberg, NIST**

David provided an overview of the objectives and action items from the Buildings to Grid (B2G) working group.

#### **Richard Schomberg, EDF**

Richard reported on the outcomes from the Transmission & Distribution (T&D) working group.

#### **Dave Hardin, Invensys**

As co-chair of the Industrial to Grid (I2G) working group, Dave outlined the prioritized objectives from the workshop breakout.

#### **Stuart Katzke, NIST**

Stuart, as NIST's representative on the Security Issues breakout session, reported on the risks associated with a smart grid, and how to mitigate them.

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## RECOGNIZED PAPERS:

A paper from each track was selected that exemplified a message about interoperability and advanced ideas that close the "distance to integrate."

- **"Defining Common Information Model (CIM) Compliance," by Stipe Fustar (Power Grid 360)** was selected from the Architecture Track for proposing a level of compliance

ranking system that can improve planning integration efforts and encourage conformance to a semantic standard.

- **“Enabling Cost-Effective Distribution Automation Through Open Standards AMI Communication,”** by **Matt Spaur and Michael Burns (Itron)**, was selected from the Technology Track for excellent use of the GWAC Interoperability Context-Setting Framework to present the level of interoperability agreement in an area that can improve smart metering integration.
- **“MultiSpeak® and IEC 61968 CIM: Moving towards Interoperability,”** written by **Gary McNaughton (Cornice Engineering), Greg Robinson (Xtensible Solutions), and Gerald Grey (Consumers Energy)** was recognized in the Business and Policy Track for reporting on harmonization of independent and overlapping standards in the electric distribution area that advances the integration and interoperation of a greater number of product offerings.

## APPENDIX A. AGENDA

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TUESDAY, NOVEMBER 11, 2008

8:00	Registration
9:30	<a href="#">Opening Keynotes</a>
10:30	Break
11:00	<a href="#">Foundational Session</a>
12:00	<a href="#">Tuesday Lunch</a>
1:30	NIST Workshop Knowledge Base and Landscape Map <a href="#">B2G Interoperability Status</a> • <a href="#">I2G Domain Interoperability Status</a> • <a href="#">H2G Domain Interoperability Status</a> <a href="#">T&amp;D Domain Interoperability Status</a> • <a href="#">B&amp;P Brainstorming</a> • <a href="#">CS Brainstorming</a>
3:00	Break
3:30	NIST Workshop Knowledge Base and Landscape Map (Continued...) <a href="#">B2G Interoperability Status</a> • <a href="#">I2G Domain Interoperability Status</a> • <a href="#">H2G Domain Interoperability Status</a> <a href="#">T&amp;D Domain Interoperability Status</a> • <a href="#">B&amp;P Brainstorming</a> • <a href="#">CS Brainstorming</a>
5:00	<a href="#">Engagement Activity</a>
6:00-7:00	Expo & Networking Reception

## WEDNESDAY, NOVEMBER 12, 2008

8:00	<b>Registration</b>		
8:30	NIST Workshop Roadmapping Sessions <a href="#">Interoperability Goals and the NIST program</a> • <a href="#">I2G Interoperability Goals and the NIST Process</a> • <a href="#">H2G Interoperability Goals and the NIST Process</a> <a href="#">T&amp;D Interoperability Goals and the NIST Process</a> • <a href="#">B&amp;P Roadmap</a> • <a href="#">CS Roadmap</a>		
10:00	Break		
10:30	NIST Workshop Roadmapping Sessions (Continued...) <a href="#">Interoperability Goals and the NIST program</a> • <a href="#">I2G Interoperability Goals and the NIST Process</a> • <a href="#">H2G Interoperability Goals and the NIST Process</a> <a href="#">T&amp;D Interoperability Goals and the NIST Process</a> • <a href="#">B&amp;P Roadmap</a> • <a href="#">CS Roadmap</a>		
12:00	<a href="#">Wednesday Lunch</a>		
	<b><a href="#">Architecture</a></b>	<b><a href="#">Technology</a></b>	<b><a href="#">Business &amp; Policy</a></b>
1:30	<a href="#">eCommerce Approaches</a>	<a href="#">Communications Networking</a>	<a href="#">Consumer Perspective</a>
2:45	Break		
3:15	<a href="#">Architectural Concepts</a>	<a href="#">Demand Response Experience</a>	<a href="#">Enabling Policy</a>
4:30	Break		
4:45	<a href="#">Conformance</a>	<a href="#">Integrating Residential Resources</a>	<a href="#">Stakeholder Coordination</a>
6:00	Free time		
7:00-9:00	<a href="#">Dinner</a>		

## THURSDAY, NOVEMBER 13, 2008

8:00	<b>Registration &amp; Coffee</b>		
8:30	NIST Workshop Action & Planning Sessions <a href="#">B2G Action Planning</a> • <a href="#">I2G Action Planning</a> • <a href="#">H2G Action Planning</a> <a href="#">T&amp;D Action Planning</a> • <a href="#">B&amp;P Action Planning</a>		
10:30	Break		
	<b><a href="#">Architecture</a></b>	<b><a href="#">Technology</a></b>	<b><a href="#">Business &amp; Policy</a></b>
10:45	<a href="#">Secure Systems</a>	<a href="#">T&amp;D Case Studies</a>	<a href="#">Utility SG Strategies</a>
12:00	Lunch		
1:00	<a href="#">Demand Response Architecture</a>	<a href="#">T&amp;D Information Networks</a>	<a href="#">Standards Coordination</a>
2:15	Break		

2:30	<a href="#">Closing Plenary</a>
4:00	End of Grid-Interop 2008

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## APPENDIX C: PAPERS

PAPERS		
Page	Title	Authors
C-1	<i>Ontological Requirements of the Service-Oriented Grid</i>	Toby Considine
C-5	<i>New Applications of Electronic Commerce Technology to Energy, Buildings, and Capital Management</i>	William T. Cox and Toby Considine
C-12	<i>The Probabilistic Correctness of Conformance and Interoperability Testing</i>	Rik Drummond
C-22	<i>Defining Common Information Model (CIM) Compliance</i>	Stipe Fustar
C-29	<i>Scenarios for Consuming Standardized Automated Demand Response Signals</i>	Ed Koch and Mary Ann Piette
C-37	<i>Using the Intelligrid Methodology to Support Development of a Smart Grid Roadmap</i>	Mark McGranaghan, Don Von Dollen, Paul Myrda, and Joe Hughes
C-42	<i>An Intelligent Demand Side-Control of Distributed Generation</i>	Glenn Platt
C-47	<i>An Approach for Open and Interoperable AMI Integration Solution</i>	Gerald Gray, Mark Ortiz, Shawn Hu, and Joe Zhou
C-55	<i>The GridWise Olympic Peninsula Project Results</i>	Ron Ambrosio
C-59	<i>Enabling Cost-Effective Distribution Automation through Open Standards AMI Communication</i>	Matt Spaur and Michael Burns
C-63	<i>Issues and Options for Advanced Networking Infrastructure for Energy Systems</i>	Joseph Hughes and John Day
C-67	<i>Smart AMI Solutions Enable the Smart Grid</i>	Srini Krishnamurthy
C-73	<i>Integrating the Smart Grid: Ensuring You Aren't Outsmarted by the Smart Grid</i>	Gary Ockwell
C-81	<i>Linking Continuous Energy Management and Open Automated Demand Response</i>	Mary Ann Piette, Sila Kiliccote, and Girish Ghatikar
C-88	<i>Going the Distance to Connect Consumers to the Smart Grid: The New Frontier for Energy Efficiency and Interoperability</i>	Adrian Tuck
C-94	<i>Interactions Between AMI and DA/DMS for Efficiency/Reliability Improvement</i>	Robert W. Uluski

**PAPERS**

<b>Page</b>	<b>Title</b>	<b>Authors</b>
C-97	<i>Smart Grids and AMI: Understanding the Big Picture</i>	Subramanian Vadari and Jeffrey Taft
C-103	<i>Real-World Planning for Smart Grid</i>	ML Chan
C-109	<i>Utility Standards Board: Utilities Develop Business Requirements for Interoperable Smart Grid Standards</i>	Frances Cleveland
C-115	<i>Regulations, Standards, and Beethoven: How Regulations Shape Technology in Electricity and Telecommunications</i>	Eric Hsieh
C-120	<i>Implementing the Smart Grid: Challenges and a Go-Forward Strategy</i>	Ali Ipakchi
C-127	<i>MultiSpeak and IEC 61968 CIM: Moving Towards Interoperability</i>	Gary McNaughton, Greg Robinson, and Gerald Gray
C-133	<i>KPIs in Your Pocket: Leveraging Mobile Technologies for Improved System Demand Initiatives</i>	Michael Saucier
C-138	<i>Achieving Smart Grid Interoperability through Collaboration</i>	Matt Wakefield and Mark McGranaghan
C-145	<i>Sustainable Energy Portfolio Management in Support of the Smart Grid Concept</i>	Bartosz Wojszczyk, Robert Uluski, Carl Wilkins, and Johan Enslin
C-152	<i>Next-Generation Power Information System</i>	Fred Elmendorf, Mark McGranaghan, Zhiming Dai, and Chris Melhorn

# Ontological requirements of the Service Oriented Grid

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## Abstract

Process oriented integration of the power grid will be unable to scale out to support future diversity of systems and interactions. The approaches of service oriented architecture (SOA), applied to the processes in buildings and in the power grid, as well as to consumer interactions in intermittently connected devices and storage, provide a way around this barrier to smart integration.

Service oriented coordination of building services will open up new avenues for energy re-allocation and conservation. Service orientation deals with the diversity of building systems while providing the building owner/operator with new understanding of the costs and benefits of controlling power use.

The service oriented grid (SOG) must apply the same approaches to its own interfaces. Building-grid interactions must move past mere availability and consumption to include cost, quality, and projected reliability. On-site and microgrid energy sources will use the same surfaces as do grid-based sources.

Many hope that electric cars and their batteries will be a means to peak shaving and demand smoothing. Cars could instead increase demand volatility. Drivers, automobile producers, and the grid need a common vocabulary for the acquisition, storage, and use of power for use.

Ontologies naming building-based and grid-based services will enable applications for enterprise and consumer. The SOG will use them to enable technical and business innovation.

## 1. SEMANTIC MISMATCH BETWEEN BUILDINGS AND ENERGY

Process oriented integration of the power grid will be unable to scale out to support future diversity of systems and interactions. The approaches of service oriented architecture (SOA) enable orchestration of diverse technologies managed by different organizations. SOA can be applied to the processes in buildings and in the power grid, as well as

to consumer interactions in intermittently connected devices and in energy storage.

### 1.1. The Information Gap

We do not make effective decisions about things we do not understand. Deep process information only makes sense experts within the domain of that process. Facilities owners and operators are unable to make decisions based upon the details of building control systems.

Control system integration has traditionally been detail oriented and process specific. Control system performance is usually described in terms of process results or code compliance. Code compliance leads only to minimum results, ones that the decision maker cannot opt-out of. Process outcomes are typically expressed in technical results that do not map easily to business goals. For example, HVAC CFM is not easily mapped to business goals such as Tenant Satisfaction and Lease Retention

Because of the information mismatch, building decision makers are not able to make decisions to produce maximum response to economic signals such as Demand / Response. This leaves engineers to design minimal responses with the goal that the tenant does not notice.

### 1.2. The Engineers Perspective

Building operations are described in procedural or algorithmic terms. Information is siloed so there may be no direct way to measure performance; systems traditionally report only their internal metrics. These metrics are likely to be reports of measurable physical qualities, free of business context.

Examples are reporting air conditioning performance in terms of CFM of air or battery status in terms of crystal degradation.

### 1.3. The Building Owners Perspective

To the facility manager or leasing agent, service curtailment can only have bad results. Customer Complaints will increase. A tenant may not renew a lease. A single month of vacancy coupled with between-tenant renovations could easily swamp the benefit of demand-response during the year. It is better not to take a risk.

#### 1.4. The Building Tenant's Perspective

Sustainable operations have value only as tie-breaker between equivalent properties. There is no way to see or to understand building system operations on a daily basis. Without a way to audit performance of buildings, *my comfort, right now* is the only effective measure of competent operations.

#### 1.5. Barriers to Innovation

Process-to-process interactions require that the integrator be aware of the operations of each system or domain. Changes in one system require re-integration with the next. Traditional integration leads utilities to specify a single brand of a single component, often a twenty year decision. Complexity is managed by eliminating diversity.

The largest source of diversity on the grid is the end nodes. Different purposes and individual tastes are served by different vintages of equipment. Traditional grid integration has simplified this interaction to the single point of the dumb meter and perhaps a signal to the water heater or air conditioner. As the future grid becomes the intelligent grid, this one way non-interaction will not be enough.

Future build technologies are likely to be more diverse than now. Each building may have a different mixes of systems for energy storage, energy conversion, energy recycling, and energy generation. Site-based decisions will support different technologies to support each of these functions. It is in all our interest to encourage innovation and competition between developing technologies to support these functions. This requires that we minimize integration costs between different technologies. We cannot afford for difficulty of integration to be the single largest source of market friction blocking innovation.

Integration patterns must support greater agility while requiring less deep domain knowledge of emerging energy technologies.

## 2. DEVELOPING BEST PRACTICES IN ADJACENT DOMAINS

Service definition and service alignment are the key concepts in IT systems integration and in facilities design. In either case, best practices are to define the service deliverables expected from each system and not the techniques and technologies to deliver the service.

Once the service is agreed upon, then one can define useful metrics as to how well that service is delivered. Measurements that are incidental to that service delivery are not interesting to those procuring the service. Alternative technologies and approaches that deliver those new metrics become acceptable alternative, spurring innovation.

The entity with the domain expertise to create, maintain, and evolve a given capability may not have the expertise or the

desire to create, maintain, and evolve its service access. Visibility, interaction, and effect define the service.

#### 2.1.1. Service Orientation: the IT Perspective

Service Oriented Architecture (SOA) is a paradigm for organizing and utilizing distributed capabilities that may be under the control of different ownership domains. Capabilities to solve or support a solution for the problems they face in the course of their business. SOA provides a powerful framework for matching needs and capabilities and for combining capabilities to address those needs.

Visibility, interaction, and effect are key concepts in SOA. Visibility refers to the capacity for those with needs and those with capabilities to be able to see each other. This is typically done by providing descriptions for such aspects as functions and technical requirements, related constraints and policies, and mechanisms for access or response. The descriptions must be in a form (or must be transformable to a form) in which their syntax and semantics are widely accessible and understandable. Whereas visibility introduces the possibilities for matching needs to capabilities (and vice versa), interaction is the activity of using a capability.

SOA practitioners distinguish between public actions and private actions. Private actions are inherently unknowable by other parties. Public actions result in changes to the states that are shared between at least those involved in the current execution context. Real world effects are couched in terms of changes to this shared state. A cornerstone of SOA is that capabilities can be used without needing to know all the details.

SOA is not itself a solution to domain problems but rather an organizing and delivery paradigm that enables one to get more value from use both of capabilities which are locally "owned" and those under the control of others. Although SOA is commonly implemented using Web services, services can be made visible, support interaction, and generate effects through other implementation strategies

#### 2.1.2. BIM: Enabling Owner Participation

Building Design approaches and business models are being re-written using the standards-based Building Information Model (BIM). BIM can include all information related to the design, procurement, and operation of a building, including the three dimensional Building Model. In the U.S., BIM as been codified in the National BIM standard (NBIMS). Internationally there is an effort to adopt NBIMS operating as buildingSmart. BuildingSmart is a transformative peer organization whose goals, scope, and reach can be compared to GridWise.

A core value of buildingSmart is granting authority to the Owner of a building to make design decisions by expressing them in terms of business deliverable early in the design

process. For example, when reviewing the three dimensional rendering of alternate building design options, the owner can directly compare projected costs per square foot and net leasable space for each. This changes design selection into esthetics, capitalization, and revenue, and puts the business decision maker in charge.

BIM has many other benefits, especially in the areas of construction planning and process, but those are outside the scope of this article.

Today's BIM lacks any language to unambiguously discuss the desired system performance of a building. Building system performance relies on knowledge sets that are not possessed by most architectural firms. This has negative effects on commissioning and operations. This also precludes the owner from specifying and obtaining the same level of control over building operations as over the other design criteria.

### 3. ONTOLOGIES AND SEMANTIC DEVELOPMENT

If we cannot agree what to call it, we cannot compare services to provide it; semantics are an essential part of SOA. For the grid, semantic alignment will open up interoperability without locking in technology. When people can name it, then they can buy it on an open market.

But the intelligent grid will require intelligent partners. We must develop business and tenant oriented semantics for building services in parallel with the grid efforts to enable full interoperable responsiveness on both sides of the meter.

#### 3.1. Grid Semantics

Availability, price, and consumption are essential components for any service. For any but the least interesting markets to develop, the semantic interface needs to allow for more meaning:

**Capability & Reliability:** Capacity / Capability / Availability (including time windows) / Anticipated Reliability / Marginal Price

**Market Operations:** Power Use curves, Negotiation & Contracts, Offer and Acceptance, Scheduling options, Periodic price curves. Settlement. Contracted Curtailment DR

**Multi-party & Mobile transactions:** PHEV, Non-Utility vendors, identity, transactional charge override

**Tariffs:** Distance charges, transmission, carbon taxes...

**Attributes & Amenities:** Carbon, Wildlife, Location... Optional attributes for later definition and market building.

#### 3.2. Building Semantics

Buildings are occupied by different enterprises each with its own values. There will not be common ontology for all of them.

Efforts are underway in the building areas, particularly in the buildingSmart process, to define value semantics for owners and tenants. These standards are defining the services provided by building-based systems and creating a semantic of service performance.

To a business, an ontology is a business value proposition; each business has its own. The common semantics defined as above create a common way to discuss that proposition, and to elevate the quality of those services into core business concerns...and that which a business can name and measure, it will control.

Building-based ontologies, though, will not be brought to the grid. They are domain specific. Building-side semantics are used to bring internal energy use under management and control.

Buildings will use the demand side of the grid semantic interface. Capacity / Capability / Availability become market demand. Market Operations become symmetrical negotiations. Multi-party & Mobile transaction become federated identity management. Attributes & Amenities support the businesses internal ontology. These semantics will enable the Service Oriented Building (SOB).

#### 3.3. Cross-over semantics

Zero net energy buildings are buildings that manage internal generation, storage, conversion, and recycling of energy. Zero net energy buildings will use diverse site-appropriate technologies to accomplish these ends. Zero net energy buildings will require internal interoperability standards and support internal energy negotiations.

The principle of parsimony suggests that at least some of these negotiations can best be performed using the semantics or energy scarcity and value, of supply and distribution for these internal negotiations.

#### 3.4. Plug-In Cars, Hybrid and Otherwise

Many hope that electric cars and their batteries will be a means to peak shaving and demand smoothing. Cars without management are more likely to increase demands on the home, office, and local distribution.

Drivers, automobile producers, and the grid require a common vocabulary for the acquisition, storage, and use of power. There is no need for this vocabulary to be different than that outlined above as the cross-over semantics for buildings.

### 3.5. Semantics enable Security

Traditional power grid security has been based on isolation. New two-way interaction patterns require that energy systems no longer be isolated. This requires that security be reconsidered

Security without context is meaningless. Security without context can only say no. Key opportunities in energy management are lost because current business models do not share even such basic information as consumption data in real time. At the same time, non-granular security puts all operations at risk from any intrusion.

Where possible, systems should not share deep process information, but present only the information required for interoperation and safety. This informational interface presents a smaller attack surface to the outside world. Each such system defends its own mission first, and responds to the outside world only in defined ways.

As we standardize these simplified modes of interoperability, interactions move from the low level process to the higher level business function. Different technologies, such as small point-generation systems may present the same business function. A storage system may present two business functions, one as a consumer of power, and one as a sporadic producer of power. The deep process of each technology would be hidden from the operational interface. This in itself provides one layer of a defense in depth security.

The vocabulary that names these business functions maps more easily to business rules of who may do what. These rules are more understandable to the observer or security auditor, another source of security. The business semantics become one layer of a multi-layer security model.

## 4. CONCLUSION

Future energy technology will place more technical diversity than today in closer interaction. Process oriented integration of the power grid will be unable to scale out to support such diversity of systems and interactions. Service level integration will be applied to both the processes in buildings and in the power grid and to consumer interactions and intermittently connected devices.

Service oriented coordination of building services will open up new avenues for energy re-allocation and conservation. Service orientation deals with the diversity of building systems while providing the building owner/operator with new approaches to controlling power use.

The SOG will apply the same approaches to its own interfaces, those between Generation, Transmission, Distribution, and Consumption. Building-grid communications will move past mere availability and consumption to include cost, quality, and projected

reliability. On-site and microgrid energy sources will use the same surfaces as do grid-based sources.

Service based integration is the way to expand intelligence and interaction of the grid and its end-nodes. Service definitions will prevent integrations from becoming enmired in atomic interactions. Ontologies naming building-based and grid-based services will enable applications for enterprise and consumer. The SOG and the SOB will hide complexity to enable technical and business innovation.

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## Biography

Toby Considine has been integrating building systems and business processes for longer than he cares to confess. Since the Y2K push ended with the post-midnight phone call from the University of North Carolina Cogeneration Plant, Toby's focus shifted to standards-based enterprise interaction with the engineered systems in buildings.

Toby has been chair of the OASIS oBIX Technical Committee. oBIX is an unencumbered web service designed to interface between building systems and e-business. In the summer of 2008, he became co-chair of the OASIS Technical Advisory Board. He is active on the NIST Smart Grid Domain Experts Group and works to promote applying information technology to with groups such as buildingSmart and FIATECH.

Before coming to the university, Mr. Considine developed enterprise systems for technology companies, apparel companies, manufacturing plants, architectural firms, and media companies old and new. Before that, Toby worked as a biochemist following undergraduate work in developmental neuropharmacology at UNC.

Mr. Considine is a recognized thought leader in applying IT to energy, physical security, and emergency response. He is a frequent conference speaker and provides advice to companies and consortia on new business models and integration strategies.

# New Applications of Electronic Commerce Technology To Energy, Buildings, and Capital Management

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## Abstract

We discuss application of electronic commerce technologies to building and energy management. Our examples focus on home systems, but the techniques apply virtually unchanged to commercial and industrial environments.

Traditional power grid / home interactions involve low-level control interactions and direct communication with the target devices. Widely used eCommerce interactions can provide control that is at least as fine-grained while enabling the homeowner to maintain primary control of his own domicile. Ecommerce interactions are technology agnostic and general purpose; the same signal can interact with multiple site-based systems, resulting in greater scalability and interoperability.

Service-based systems provide natural end-points for economic signals. Agents can encapsulate domain knowledge of each system while providing a well-defined common service interface for interaction. Agents can also be aware of other systems in the house, offering additional opportunities for optimization. Most importantly, agents can be aware of the owner, the owner's schedule, and the owner's wishes. Systems that preserve and enhance homeowner autonomy will see greater long-term acceptance

Economic signals place responsibility for delivered performance on the local system, they align performance with responsibility. Because they enhance interoperability, they increase competition and expand innovation. Because economic signals make costs and opportunities transparent, they encourage site-based investment in new systems.

Our approach is fully consistent with the GridWise Interoperability Principles [25] and leverages broadly used business definition, management, and monitoring

technologies, while allowing the same set of services to be used in many environments.

We can accelerate the movement to dynamic pricing and effective use of energy by not reinventing functionally similar standards.

## 1. INTRODUCTION

We apply electronic commerce (eCommerce) technologies to energy management, using economic interactions as a means to better shaping of both demand and for tailoring consumer-side activities to maximize economic benefit from energy suppliers to consumers.

Markets are the best means for effective management of resources, exploiting the elasticity of demand for energy by passing through pricing information, which in turn is correlated to cost information. The interactions defined here allow us to reduce infrastructure use, and hence reducing or delaying required capital inputs for improving transport and distribution infrastructure.

Markets have developed for demand curtailment commitments [1] and demand response [2], today primarily in the industrial and commercial energy markets. Limiting and shaping demand by pricing has demonstrated value both for infrastructure use and distribution. Monetization of demand curtailment suggests that the limitation and shaping of demand we describe here is valuable, and may be sufficient to purchase controller and information technology enhancements while saving energy costs for the consumer [3].

When we say *consumer* we mean the user of the energy purchased and then delivered through distribution systems; our examples and solutions focus on home use, but can easily be extended to commercial and industrial use.

Building and industrial controls are broadly used, so these solutions may be more easily implemented in the non-residential space.

Finally, by creating a rationale for more intelligent and responsive user agents (effectively at the consumer side), the effects of a reduction on consumption can also be monetized, increasing value of intelligence in building control.

## 2. PLUG-IN HYBRID CHARGING USE CASE

### 2.1. Description

We start with a simple use case. Consider a home with two high-wattage appliances, an air conditioner and a battery or plug-in hybrid car.

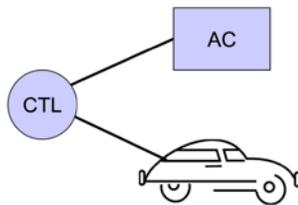


Figure 1

The controller in Figure 1 should be viewed as a service provider, not a particular piece of hardware. The functions may be located in an enhanced electric meter, at a distribution center, in the house, in the car charging station, at the air conditioner or external to the physical premises on the Internet (requiring some hardware assist close to the appliance).

The service provided is to manage energy purchase and consumption. In this simple example this devolves to distribution. Inputs will include pricing information in later elaborations; outputs include control signals to the car charging station and the air conditioner.

Note that pricing information will require (except in the simplest case) synchronized time as an input, to react to time-related changes in pricing.

### 2.2. Energy Management Issues

The worst-case scenario for this use case is as follows:

On a hot, peak energy use day, the consumer drives home at 5:30pm, plugs in the car, and turns on the air conditioning.

In single-price environments, the consumer will incur no additional energy cost, but there are substantial hidden costs:

- 1) The consumer risks the loss of use of the home environment if the energy demand leads to brown outs, black outs, or trips the main circuit breaker.

- 2) The energy provider risks higher peak generation costs.
- 3) The distribution utility risks peak loads that can interrupt or curtail use via brown outs or blackouts, which in turn affect other customers.

For similar usage issues, e.g., interruptible electric hot water heating rates, system control can limit overloading the grid but will affect the customer’s use of hot water.

This sledgehammer-like approach is similar to cutoff functions in Automated Metering Infrastructures—protect the grid, but reduce customer benefits to zero. Special care must be taken to sequence turning on customers’ power; otherwise spikes and surges in demand can take the system back down.

## 3. IMPROVEMENTS AND SOLUTIONS

### 3.1. Step One—More Intelligence

#### 3.1.1. Changes to the Model

Consider the addition of limited intelligence based on time-of-day usage patterns (and perhaps a delay function for car charging). Figure 2 shows an Agent into which we separate (metaphorically) the intelligence.

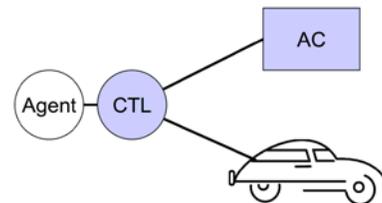


Figure 2

For example, pre-cooling before occupancy or charging the car at night will move some demand from peak times with a higher risk of interruption to lower use times with a lower risk of interruption.

In today’s flat-price markets, there is no customer benefit beyond risk mitigation, but costs to energy providers are reduced through limiting operating and capital costs for peak generating capacity. In addition, avoiding failures in the distribution network reduces costs of distribution and generation.

#### 3.1.2. Discussion

The monetization of demand curtailment markets may provide opportunity for aggregators of home consumers in addition to demand curtailment markets for present business and industrial consumers.

In existing pilots [3] whole house level demand curtailment has been at no explicit charge to the customer, who also typically saves a modest amount on electrical rates, reflecting in turn the value to energy providers and distributors.

### 3.2. Step Two—Pricing Information

We now allow price information to be obtained by the controller.

#### 3.2.1. Changes to the Model

In Figure 3 we have added agents to the air conditioner and the car, with lines connecting all controllers to emphasize that they communicate (indeed, they may be deployed to the same hardware). The controller now has access to query-response interaction (or a pushed download) for obtaining present and future pricing information.

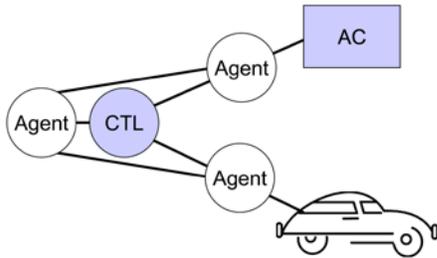


Figure 3

Obviously, full two-way interactions allow for better information; typical low-bandwidth connections through AMI or power lines to the customer make broadcast of all prices problematic.

#### 3.2.2. Discussion

Because this model uses prices rather than control, all decision making moves to the consumer. When the consumer faces unique events (tighter budget, weekend guests) the consumer is able to modulate the response. This model is likely to provide more long term satisfaction with load curtailment on a house by house basis, and thus more potential curtailment to the grid overall.

#### 3.2.3. Which Kind of Pricing

There are a number of variations of static and dynamic pricing; we follow the terminology of [4] and [5].

##### Static Pricing

- 1) Flat-rate pricing (FR)
- 2) Summer/winter pricing, or Seasonal Rates (SR)
- 3) Time-of-use pricing (TOU)

#### 4) Critical Peak Pricing (CPP)

The common feature is that pricing varies in some manner that is known in advance. With SR and TOD pricing, the information is known far in advance, and could be programmed into the controller. With CPP, expected peak days are still known in advance, but with less notice, making manual programming more difficult.

##### Dynamic Pricing

- 1) Real-time Pricing (RTP)
- 2) Price-ahead (P-A)

In RTP the controller obtains pricing information by means of a query to the supplier or distribution, a data stream pushed to the agents, or other means, possibly fairly close to the time of use. Price-Ahead (our term) describes systems where a future price vector (say for the next eight hours) is available, allowing a look ahead at future rates.

From our perspective, once the pricing information is in the agent, the algorithms are similar—determine whether an electrical use can be deferred or pulled up to a lower-cost period, and do so. The difference is overall responsiveness to both expected and unexpected events (e.g., peak usage and failures).

##### Future Pricing

We anticipate forward markets for energy; such markets have broad benefits [6]. Forward markets already exist in various forms for commercial and industrial customers. The customer's agents can make a bid or solicit quotations in a futures market. This blends seamlessly into the P-A scenario where the forward pricing limit is determined by the market rather than directly by the energy supplier. The Olympic Peninsula Project [4] did not use future pricing.

#### 3.2.4. Analysis

From our perspective, the various pricing models differ little in the agent algorithms; they differ principally in the effects (latency and gross effect) on consumption and the extent of load shaping they support.

Finer-grained and more dynamic pricing affords benefits in system and grid resilience to unexpected changes in load, demand, or peak capacities (e.g. a generator, or a transmission line failing) as well as increased flexibility in demand shaping (see e.g. [7]). In particular, there's no need to wait for tariff changes to affect pricing.

### 3.3. Step Three—More Information

We now add additional information inputs to the agents, such as actual and predicted information, for example

- 1) Weather

- 2) Occupancy
- 3) Usage

This will permit the agents to make energy efficient decisions with lessened effect on the customer's use of the premises and the car.

### 3.3.1. Changes to the Model

In Figure 4 we have added simple Web services access to the agents for obtaining additional information. We show these (one way and two way) information flows going to the leftmost agent, as we've presumed communication between them. Recall that the agents may be deployed within a single computer system, making communication easier, or distributed across a building or neighborhood.

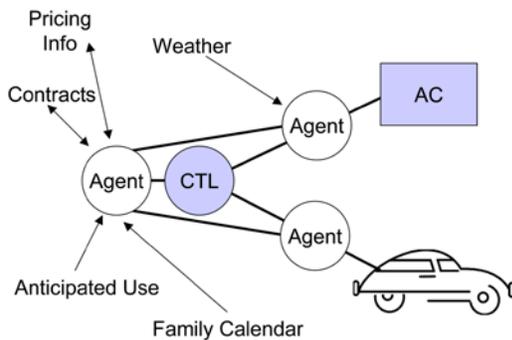


Figure 4

### 3.3.2. Discussion

In heated buildings, external temperature sensors—outdoor reset controls—have been used for decades to reduce heating costs and improve comfort [8].

In commercial buildings, occupancy information is typically available with a combination of time-of-day programs and active occupancy sensors, which may connect to building management system or (e.g.) to individual light switches. Many commercial buildings include some capacity for estimating need for a room and appropriately pre-cooling or pre-heating before use.

We extend the meaning of *anticipated usage* by including access to some form of calendar or other anticipated use information. For example, if the customer is on an extended trip, the need for cooling is reduced. If the customer has family visiting, or an event to go to tonight, it may be more important to charge the car now rather than wait until the early morning.

Incidentally, the mechanism for interruptible electric hot water does not adapt to changing short-term usage: your hot

water supply is just as interruptible when you have a house full of guests as when the house is empty.

### 3.3.3. Analysis

This model may further reduce energy consumption, but the principal goal is to add flexibility to adapt to the occupants' needs. By allowing automatic overrides, consumption can be adjusted to adapt to the occupants' needs. The goal is not additional energy savings, but to use pricing (more toward the RTP end of the spectrum) to limit costs while ensuring a minimum or desired level of comfort and utility.

## 4. REALISM OF THE MODELS

Everything described in this paper can be implemented today. The engineering of solutions needs to consider varying capital, deployment, and maintenance costs.

The functional needs of the controller include the ability to turn on and turn off the air conditional and car charging station; work such as the PNNL Appliance Controller demonstration project [9] as well as home automation and building automation technologies that perform those function with control signals from a computer.

The agent could be built from a single-board computer, or run on a household computer, or be part of a home automation system, or be an integration of distributed functions in device controllers. The agents could be implemented by the distribution utility or by a home controller manufacturer. Aggregators of demand curtailment may be a source of funding.

Information in electronic calendars is readily available, although not always in an immediately useful form. The iCalendar specification [10] is a case in point, supported by many home and commercial computing environments.

Communications deployment is an issue, not because it's difficult, but system designs and costs vary considerably. Ideally, one could use an existing Internet connection, and some AMIs permit low-bandwidth data transmission. Reasonable disconnected operation is critical [4][25].

Monitoring and measuring sensors are readily available.

We address security requirements and existing solutions in the next section.

## 5. ECOMMERCE TECHNOLOGIES

The eCommerce standards and techniques we described have mostly been broadly used for years. We can accelerate the movement to dynamic pricing and improved use by not reinventing functionally similar standards.

### 5.1. Service-Oriented Architecture

We have taken a Service-Oriented Architecture (SOA) [11] approach, although we didn't mention it in advance. SOA is

broadly used in eCommerce and enterprise software, and has benefits for modeling and implementing software solutions. See, for example, [12] for application of Semantic SOA to building services and emergency management.

### 5.2. Contracts and Purchases

The most obvious use of eCommerce technologies is the interaction to buy and sell energy. Agency and negotiation, though primitive, are well suited to these kinds of pricing and purchasing. Our examples are from broadly deployed eCommerce Web services defined by OASIS [13].

Can you trust the pricing on which you're relying? XML Digital Signature (XML DSIG) [14] can help, but it is likely better to use a reliable messaging standard that used digital signatures to both assure delivery and validate the source. EbXML Message Service (ebXML MS) [15] is such a technology, broadly used and interoperable. Other techniques are mentioned below.

### 5.3. Beyond Pricing

Web services [16] or Representational State Transfer (REST) services [17] can be used to transmit information; in the eCommerce world Web services are preferred due to the response/acknowledgement.

Reliable messaging techniques, e.g. WS-ReliableMessaging [18], can be used to ensure delivery of messages.

Event delivery and management services, e.g., Web Services Notification [19], provides publish/subscribe events.

### 5.4. Distributed Security

The experience in distributed fine-grained security for eCommerce applies directly to our example situations. See, for example [20]. You want to ensure that only the right people, in the right roles, access your home, power grid, and other infrastructure.

Security standards such as WS-SecureConversation [21], when composed with WS-ReliableMessaging [18], satisfy critical requirements of notification of demand events or pricing signals with reliable delivery.

WS-Security [22] is a framework for secure interaction, and has been in broad use in the eCommerce space for several years. OASIS' Security Access Markup Language (SAML) [23] allows the creation of secure tokens that can be passed and validated to allow specific access, and eXtensible Access Control Markup Language (XACML) is used to define fine-grained access controls [24].

## 6. BENEFITS AND INTEROPERABILITY

In this section we briefly discuss how our approach relates to the GridWise Interoperability Principles [25], and the benefits of using the eCommerce approach.

### 6.1. GridWise Interoperability Principles

We use the statement of principles [25] rather than the more detailed GridWise Interoperability Framework [26].

Our proposals address the Business Principles and Information Technology Principles, permit satisfaction of the Usability Principles, and do not address the Regulatory and Governance Principles.

We satisfy B01 in that we address information exchange and boundary interfaces, consistent with SOA. Security and privacy concerns have been addressed with the portfolio of security standards we have listed.

Change is a fact of life in enterprise and eCommerce systems, which have long experience addressing B02.

The eCommerce techniques are used for many marketplace transactions, and are applicable to those envisioned in B03.

We do not directly address B04, as we have not examined costs/benefits and affects to the parties; this is part of an architectural and deployment plan.

Verification and auditability are addressed in eCommerce systems; this is an architectural and deployment requirement (B05).

Interoperability through service definitions addresses many of the integration issues in the principles; SOA is a best practice in enterprise software definition and deployment. (I01, I02). SOA addresses multi-company applications (I03), and typically uses Business Process, Business Data, and other modeling methods (I04).

Enterprise and eCommerce systems have substantial privacy and security requirements, many enforced by law, and have successfully evolved over time. (I07).

By definition, an eCommerce approach supports I08, and commercial implementations (often composed of open source components) have an excellent record of meeting performance, reliability, and scalability requirements (I09).

Finally, deployed enterprise and eCommerce systems have successfully dealt with multiple versions of specifications and technologies; care must be taken in both standards evolution and implementation to ensure consistent success.

### 6.2. Benefits of Using eCommerce Technology

By moving the definition of interfaces to the service level the eCommerce approach limits details of interaction that make brittle interfaces; the details of (say) a BACnet or LONmark interface when abstracted to a higher service level are not crucial to the service interactions. Of course, those interfaces and detailed monitoring are critical to properly managing building systems, but that level of detail does not need to be reflected in service definitions [12]. This

gives flexibility to service definitions and greater ability to reuse and repurpose.

When engaged in economic interactions, only the price and characteristics of the service supplied are relevant—by ignoring other details, the interfaces are simplified and made more robust.

Decades of experience in enterprise systems (e.g. multi-tier database systems for managing business information) have shown great scalability as businesses have grown.

In addition, by adapting and reusing eCommerce interactions and security, we can accelerate the movement to dynamic pricing and effective use of energy by not reinventing functionally similar standards.

## 7. CONCLUSIONS

We have limited our examples to homes with two high-wattage appliances; this is clearly not realistic, but the behavior of the largest consumption appliances dominates those of lower demand appliances. Finer grained control has been explored (e.g. by [9]) but our simplification exposes the major effects.

The techniques used are essentially the same when applied to all consumers of RTP in residential, commercial, and industrial. Some extensions to the basic services may be useful for commercial and industrial consumers; see Future Work.

Future homes will have more large energy-using systems than today. Future homes will have a mix of energy technologies, including site-based generation and site-based storage. This transition will be mediated by a clear recognition of the costs and benefits; eCommerce interactions will make these benefits quantifiable. eCommerce style interactions inside the house may prove to be the most efficient means to integrate diverse systems within the house as they reduce the detail that needs to be understood by each party to the transaction.

## 8. FUTURE WORK

We have not addressed in detail the controller services or other characteristics. This is in keeping with our architectural analysis of information flows. Clearly a concrete input is needed for implementation; there is much work in this area, and many products and pilots.

We have not addressed the necessary design of markets to support the pricing models we have discussed, in particular futures and more competitive “spot” markets for energy.

The next steps in this work are to define the services more fully, and validate our notion that the same service interfaces can (with perhaps extensions) apply from residential to commercial to industrial situations.

Demand elasticity information gathered from [4] and [5] will be a useful input into models to estimate energy consumption changes and peak demand changes to better determine cost-effective choices.

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## Biography

William Cox is a leader in commercial and open source software definition, specification, design, and development. Bill is an elected member and Co-Chair of the OASIS

Technical Advisory Board, where he advises the Board and membership of the leading XML and Web services standards organization in the world.

Bill has developed enterprise product architectures for Bell Labs, Unix System Labs, Novell, and BEA, and has done related standards work in OASIS, ebXML, the Java Community Process, Object Management Group, and the IEEE, often working the boundaries between technology and business requirements. He was lead architect for Unix System V Release 4 and of follow-on highly scalable and secure Unix systems, service-oriented architectures and directory APIs for Novell, Web services and XML messaging and transaction systems, and other enterprise software.

He earned a Ph.D. and M.S. in Computer Sciences from the University of Wisconsin-Madison.

Toby Considine has been integrating building systems and business processes for longer than he cares to confess. Since the Y2K push ended with the post-midnight phone call from the University of North Carolina Cogeneration Plant, Toby's focus shifted to standards-based enterprise interaction with the engineered systems in buildings.

Toby has been chair of the OASIS oBIX Technical Committee. oBIX is an unencumbered web service designed to interface between building systems and e-business. In the summer of 2008, he became co-chair of the OASIS Technical Advisory Board. He is active on the NIST Smart Grid Domain Experts Group and works to promote applying information technology to with groups such as buildingSmart and FIATECH.

Before coming to the university, Mr. Considine developed enterprise systems for technology companies, apparel companies, manufacturing plants, architectural firms, and media companies old and new. Before that, Toby worked as a biochemist following undergraduate work in developmental neuropharmacology at UNC.

Mr. Considine is a recognized thought leader in applying IT to energy, physical security, and emergency response. He is a frequent conference speaker and provides advice to companies and consortia on new business models and integration strategies.

# The Probabilistic Correctness of Conformance and Interoperability Testing

## *The Probabilistic Conformance & Interoperability Correctness Theorem*

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**Keywords:** Conformance, Interoperability, Testing, Correctness, Probability

### Abstract

The common understanding of interoperability and conformance testing and their interrelatedness is fraught with bad assumptions and false ideas. Myths like conformance tested products are automatically interoperable and interoperability tested products are automatically conformant lead to greatly diminished returns within eBusiness systems and supply chains. Testing programs intended to help a community can instead hinder it if wrong conclusions are made regarding the interoperability and conformance of its products. Yet, without a widely accepted method and understanding of interoperability and conformance testing, the cycle of unmet expectations and undelivered promises will continue. There is a great need for a universal method to analyze and predict real-world interoperability and conformance of different testing processes.

This paper provides logical proofs and mathematic theorems to provide this needed analysis. The paper works out the mathematical basis for the probability of conformance and interoperability of testing procedure. Understanding and application of this probability analysis allows for implementers to better assess the expected results from certified testing programs.

This paper provides a logical and mathematical foundation for guidance in answering critical questions a test program must consider, such as:

- How many implementations must be tested for an interoperable product or a conformance engine to become reasonably conformant?
- How do you test for both interoperability and conformance?

- Why are eBusiness implementations problematic in testing for achieving both interoperability and conformance?
- Why do we have to be careful if organizations developing the products and the conformance or interoperability testing organization have significant communication about the standard?
- Do we always need to test for both conformance and interoperability or are their cases where we can save resources by only doing one and achieve or closely achieve the other?

## 1. INTEROPERABILITY AND CONFORMANCE TEST STRUCTURES

### 1.1. Introduction

In order to purposefully discuss interoperability (IOP) and conformance testing, it is important to fully comprehend the industry concepts and lingo in this arena. Several concepts must be discussed to enable a clear understanding of the various complexities and nuances involved in both types of test structures.

These tests are verifying the accuracy of various implementations of a specification. A *specification* is a pre-test agreement among implementers with sufficient detail and exactness as to allow the evaluation of an individual implementation's accuracy with regard to meeting the specification's conditions. This covers profiling as well as specifications that are not standards but are done when two or more companies decide to intercommunicate in a more ad hoc manner. Finally, it *may* cover all standards, such as HTTP, on which the specification is based. This is necessary because a specification is often tested for conformance or interoperability (IOP), yet does not test the supporting standards. These base standards may not be conformant in the implementations and could potentially cause an interoperability problem. For example, when using HTTP,

the systems under test (SUTS) do not know whether the code is conformant to HTTP specifications or if it has been profiled correctly across all the implementations.

### 1.2. Conformance Test

A conformance test of an application shows that the application conforms to the specification by interacting with the **conformance engine application**. During this type of test, the conformance engine (CE) generates output and receives input which is evaluated by implementations R1 through Rn-1 (Figure 1) and the CE. Both input and output from the interaction with the CE are expected to be conformant to the specification. The CE output is NOT evaluated by the conformance engine itself, because it is expected to be correct. The only verification that the CE output is correct comes by consensus from the participating systems R1 through Rn.

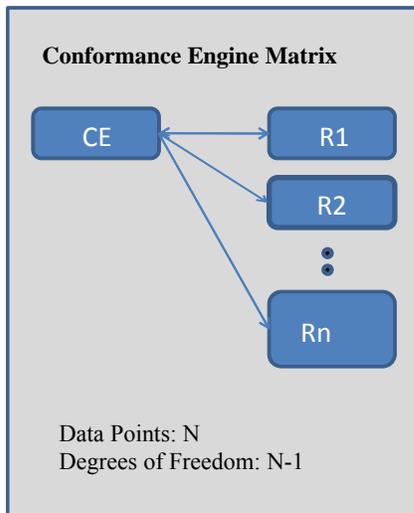


Figure 1

An implementation of a specification is said to be **conformant to the specification**, IF and only IF, the input  $domain(x, y, \dots)$ , and the output  $range(a, b, \dots)$  of the implementation meet the requirements of the specification and the relation,  $range = R(domain)$ , when  $R$  implements the requirements of the specification. This is a normal Black-box with input and output.  $R$  is the BLACKBOX, the input being the domain and the output being the range. See Figure 2. The dependant and independent variables of the range and domain may be Boolean, real, integer, documents, sets, etc. Therefore, the variables may be composed of any length bit-stream.



$R$  is a mathematical relationship.  $R$  acts like a Black Box for testing purposes.

Figure 2

### 1.3. Full Matrix Interoperability Test

A full matrix interoperability test (Figure 3) for a set of

#### Interoperability (IOP) Test Structure

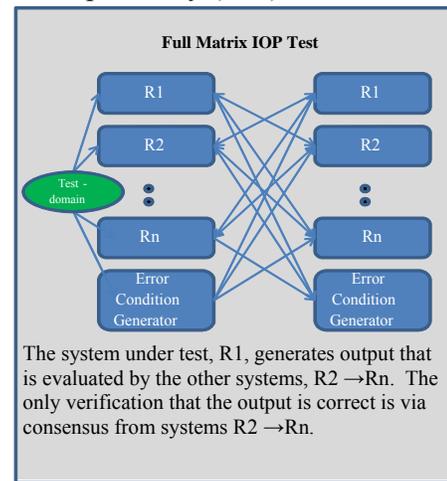


Figure 3

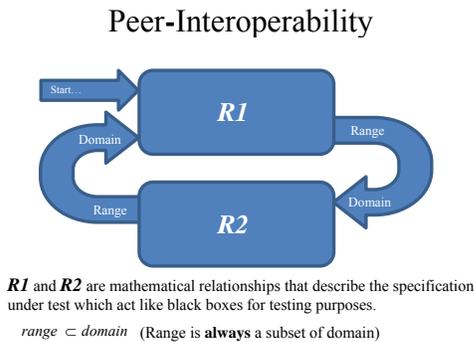
applications built on a **peer-interoperable specification** shows the applications interact properly – are peer-interoperable. Each system must initiate and respond with every other implementation in a full matrix manner as the *specification* states. Thus it must show that  $R2$  initiates and  $R1$  responds,  $R1(R2(domain))$ , and  $R1$  initiates and  $R2$  responds,  $R2(R1(domain))$ , properly. This is a composite relation. Also, both are a subset of *domain* for every pair of applications, whose relations  $R1$  through  $Rn$  are within the test and an application responds to peer implementation  $R(R(domain))$ . See Figure 4.

A *specification* is said to be peer-interoperable, IF and only IF, the input  $domain(x, y, \dots)$  and the output  $range(a, b, \dots)$  meet the requirements of the *specification*. It also requires that the relation,  $R$ , implements the requirements of the *specification* and *domain* is a superset ( $\supseteq$ ) or proper superset ( $\supset$ ) of  $R(R(domain))$ . (Figure 4) It is important to remember the dependant and independent variables of the

range and domain may be Boolean, real, integer, documents, sets, etc. Once again, the variables may be composed of any length bit-stream.

**1.4. Relation - R**

In addition to comprehending the models of conformance and interoperability testing, it is important to understand the mathematical concept of a relation. Suppose **R** is a relation from A to B. Then **R** is a set of ordered pairs where each first element comes from A and each second element comes from B. That is, for each pair  $a \in A$  and  $b \in B$  then  $(a,b) \in R$  is read as “a is **R**-related to b”. The domain of a relation **R** is the set of all first elements of the ordered pairs which belong to **R**. The range of **R** is the set of second elements [1]. Each variable, a and b from (a,b) could each represent a set of (l, m, n,...).



**Figure 4**

A relation, unlike a function, may have more than one correct output for exactly the same input. Thus a relation could have something such as (a,b) and (a,d), both being a correct response for an input of ‘a’. The relationship, versus the function, was selected for this series of definitions to make the definitions as general as possible.

In the interoperability definition, the idea of a **composite relation** ( $R1 \circ R2$ ) is revealed. Let **R1** be a relation from A to B and let **R2** be a relation from B to A.(Figure 4) Then  $(a, a) \in R1 \circ R2$  where  $(a, b) \in R1$  and  $(a, b) \in R2$ . In a **peer- interoperable specification**, **R1** and **R2** are different representations of the same specification.

**2. THEOREM: THE PROBABILISTIC CONFORMANCE & INTEROPERABILITY CORRECTNESS THEOREM**

**2.1. Theorem:**

*Any individual implementation of a set of size N implementations of **peer-interoperable specifications**, which are peer-interoperable among themselves, has the same probability of being conformant as a **conformance engine of error degree N-1**, if:*

- *the implementations are developed in a manner that produces random errors.*
- *the appropriate **error generator application** is part of the interoperability test.*
- *the same **test criteria** is used for both.*
- *the conformance engine was tested against itself.*

**2.2. Corollary:**

*Based upon test criteria, a Conformance Engine (CE) tested against N implementations or any single implementation tested against N other implementations in a full matrix IOP test has a probability of being conformant to the specification of:*

$$(1 - APE^N)^M$$

**Where** *N=number of implementations, M=number of test cases, APE = average probability of a test-error in an implementation on a test case.*

NOTE: The Theorem and the Corollary will be proved concurrently below.

### 2.3. Pre-Proof Discussion:

In Figure 5, both methods have a flaw in that each ‘may’ not identify some **test-errors** or test-discrepancies. In statistics, these standard errors are generally referred to as Type I & Type II errors.<sup>[2]</sup>

Type I Error: Rejecting a true null hypothesis. This can be restated as:

- Rejecting a true IOP system or a truly conformant system
- Reporting a test-error when the systems are truly conformant to the specification

Type II Error: Failing to reject a false null hypothesis (**testing event error**)

- Failing to identify a non-conformance error
- The systems under test agree that something is not a **test-error** when it actually is
- An error escaping thru the test regime for each test case

Throughout this proof, the discussion centers on type II errors.

#### The Key Question from which the theorem and corollary are produced is:

*How can systems be interoperable based on a specification and not be conformant to that specification?*

If one keeps this question in mind the proof will be easier to understand.

This situation can happen when all of the implementations in an IOP or conformance test make exactly the same ‘non-conformant error’. Each system would report a condition as ‘not an error’ when tests are conducted against the conformance engine or among each other. Henceforth, this situation involving a type II error will be referred to as a **testing event error**.

In Figure 5, the IOP test R1 would have to see the same test-error as a non-error for the N-1 other products in the test. In the **conformance test**, the

Theorem 3 View of Testing

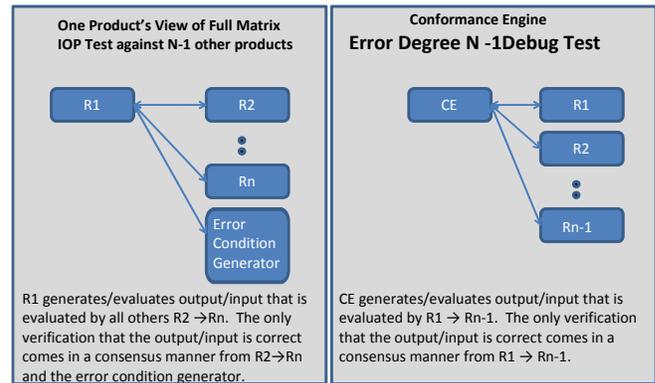


Figure 5

conformance engine would have to see the same non-error for the N products in the test in order for a real error to escape the test. The only way for this to happen is if R1 thru RN agree that a real test-error is not an error. If one implementation found the **test-error**, the specification should be checked to see if it is an error and correct all systems R1 thru RN as necessary. The same argument follows below for both test types: interoperability and conformance.

#### 2.3.1. Example:

*The specification requires that when an implementation receives an ‘A’ it should then respond with a ‘B’. This is the correct conformant response. However, if all of the implementations think that when they receive an ‘A’ they should respond with a ‘C’, then the systems all deem this as a correct response. In this situation all of the implementations pass the test. The conformance engine even passes because it is wrong also. Therefore, since all participants passed the test, then they all work. Yet, they are not conformant! The only way this can happen is if they all think sending the ‘C’ is correct. If even one of them thinks ‘C’ is incorrect, then a discrepancy will have been identified. With the proper research, the problem can be corrected.*

This can be stated mathematically as:

Given any  $a \in \text{domain}$ ,  $b \in \text{range}$ , and  $c \in \text{range}$ , the expected relation is:

$$(a, b) \in R1, (a, b) \in R2, \dots, (a, b) \in Rn \text{ and } (a, b) \in CE$$

However in a **test event error** situation, the actual result is

$$(a, c) \in R1, (a, c) \in R2, \dots, (a, c) \in Rn \text{ and } (a, c) \in CE$$

In this case, the test domain element ( $a$ ) produces the same non-range **test-error** in all implementations – ( $a, c$ ) where  $c$  is not part of the range as specified by the specification or it is the improper range element for this input ‘ $a$ ’. This includes both the implementations and the CE -- conformance engine. Now, assume the CE sets a baseline validation against the same set of **RI** through **Rn** implementations which all contain the same **test-error**. The CE could cause problems in future conformance tests by confirming that the non-range or **test-error** element is correct when it is actually incorrect for a specific domain element. A full matrix IOP test on that same set of implementations will also encounter this exact issue. If the conformance engine is completely accurate in its implementation of the *specification*, the above scenario cannot happen. However, the only way to verify that it is completely true in its implementation is to test the CE against a number of implementations or other CE’s. These systems may be colluding together to cause an incorrect output from the CE. The goal of this contrived agreement is to get the CE to return a flag of correct when it is should be returning a flag of error. The collusion would happen more often if the applications (SUTS) were developed as a group effort. This conspiracy among the implementations usually only happens when the errors in the implementations are not random in nature.

#### 2.4. Proof:

*Theorem: Any individual implementation of a set of size N implementations of peer-interoperable specifications, which are peer-interoperable among themselves, has the same probability of being conformant as a conformance engine of error degree N-1, if: the implementations are developed in a manner that produces random errors.*

- the appropriate **error generator application** is part of the interoperability test.
- the same **test criteria** is used for both.
- the conformance engine was tested against itself.

The test structure is looking for any conflicts between the implementations during *peer-interoperable* full matrix testing or verification of the conformance engine. When conflicts are discovered, they are resolved by referencing the *specification*. Thus, the issue is in identifying any conflict and then resolving the coding errors or interpretation issues in all implementations in a manner that meets the *specification*.

*As tests against the N systems which have supposedly been programmed to the specification are conducted, what is the probability of a testing conflict NOT being reported when there really is a test-error? The implementation passes the test yet remains non-conformant.*

Once a conflict is identified, verification must occur that the conflict ‘does or does not’ meet the specification. A conflict that is not revealed during a peer-interoperability test or validation of the CE on all N implementations is a test-event-error. The probability that **ALL** implementations make exactly the same non-conformant error in their implementations on one test case is:

$$(APE)^N$$

where APE is the average probability of a specific test error in an implementation.

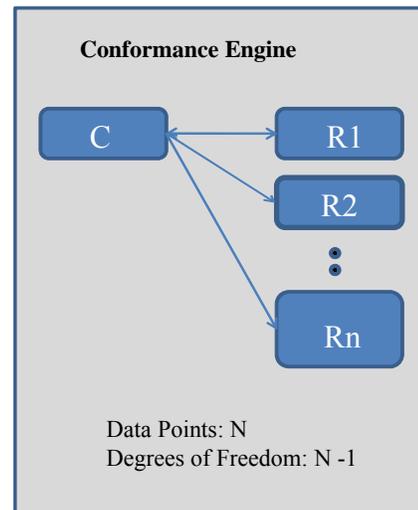


Figure 6

So again,  $(APE)^N$  is the probability of an error escaping thru the test regime for each test case. The expression below represents the chances of identifying **test-errors** for

all test participants for one test case because one to several of the implementations identify this as an error. That is, zero errors are escaping through the test for each test case.

$$1 - (APE)^N$$

What is the probability of a situation like this happening for ALL test cases? This means none (zero) of these colluding test-errors are escaping through the test procedures and we are approaching full conformance.

$$P(\text{test} - \text{event} - \text{error}) = 1 - (APE)^N$$

For all test cases, the probability of this happening is:

$$P(\text{test} - \text{event} - \text{error})^M = \left[1 - (APE)^N\right]^M$$

where M is the number of test cases.

It is important to note that the average probability of error (APE) for each implementation is assumed to be the same for each test case. Since this is not always true, it must be approximated. There isn't an easy way to quantify the probability of the error occurring in the specific test so an educated guess must suffice. This unknown value could possibly be computed as:

$$\frac{1}{\text{number of possible code sequences covered by this test case which could be in error}}$$

If the exact probabilities could be computed for each test case, the expression would be:

$$1 - (P_1(\text{test} - \text{error}) \cdot \dots \cdot P_N(\text{test} - \text{error}))$$

Or

$$P(\text{test} - \text{event} - \text{error}) = 1 - \prod_{i=1}^N P_i(\text{test} - \text{error})$$

#### 2.4.1. Example:

N=number of implementations under test = 10, M = number of test cases =20, APE = 0.10 = chances of error in an application on the same test case. We have to guess on this 0.10 because we don't know for sure the exactness of this value.

$$P(\text{conformance}) = (1 - APE^N)^M = \left(1 - \left(\frac{1}{10}\right)^{10}\right)^{20}$$

#### 2.4.2. Finally:

Now this is the chance of any one implementation or the CE being error free with respect to the test criteria. The test criteria are, of course, based on the specification and, since no errors escaped through the test, each of them has passed the **conformance** if the test plan is correct.

#### 2.5. Final Conditions:

- *The implementations are developed in a manner that produces random errors – the proof above depends on random errors. Non-random errors invalidate the proof.*

The basis of the theorem is that errors happen randomly.

- *The appropriate Error Generator application is part of the IOP test. This is required to ensure that the implementation being tested in an interoperability test have the ability to use the same test criteria as those in a **conformance test**.*

It is assumed the error generator application implements the same error test as conformance engine.

- *The same Test Criteria is used for both.*

This should be obviously clear.

- *The CE tested against itself.*

The CE in the conformance test could be less conformant than the full matrix tested products because how it responds to 'error-conditions' is not tested unless it is tested against itself.

## Key Conclusions from this paper:

- One of the most important observations drawn from the probability theorems is the necessity of a well constructed error generator within an interoperability test. The failure to provide one prevents the conformance and interoperability testing from properly establishing the boundaries of the test domain and verifying the products under test truly meet the standards' requirements. A test event which does not use the error generator must be very carefully designed to prevent deployment level interoperability issues from arising.
- The necessity of the error generator points to the fact that testing organizations have to be careful in their communication with organizations developing the products regarding the standard under test. If there is significant dialogue between those developing the implementation and the test organization, they may all make the same error with reference to 'the standard'. If this occurs, the chances are greater that, during the test event, all the implementations may evaluate this 'error' as a 'non-error' and thus evaluating implementations as interoperable and conformant – yet they may not be in reality.
- Assuming the presence of an error generator and well designed testing environment, the probability formula shows that around 10 or more implementations being interoperability or conformance tested gives a significant level of conformance to the implementations from interoperability only test and to the conformance engine in the conformance only test case – for a reasonable APE. However, note that the APE has to be estimated from knowledge of the testing environment and the standard. Significantly less than ten implementations may not “clean” the conformance engine enough in a conformance test. It depends on the value of APE chosen and the number of individual test cases.
- The probability proofs also speak of the value for both conformance testing and interoperability testing for products. While the theorem does not address this directly, one of the assumptions is that the specification will be tested during both types of test. The specification definition is 'loose' in that it could apply to just 'the single standard' or to all 'associated standards on which the main standard is based'. For some test environments there is 'the standard', constructed in a manner that is very independent of other standards – some areas of devices are an example – so test criteria covers only the software or firmware on which the core standard is based. When this

environment is evident, the probability of conformance producing interoperability is much higher than in the environment where 'the standard' is strongly dependent or includes additional 'other software' such as in the case of eBusiness kindred software or firmware. This lower interoperability probability occurs because the test criteria does not cover the 'other software'.

Frequently we do not know if the 'other software' is conformant or interoperable. In this complex environment such as seen in eBusiness software and/or firmware, adding test criteria for this 'other software' would add too much effort to the actual test event and generally it is not done or only done partially. In the end, the conformance engine does not evaluate the 'other software' and does not expose the interoperability problems among the 'other software' area. The converse is true that the probability of interoperability testing achieving a significant level of conformance is less over standard implementations highly dependent on this 'other software'. With this type of standard, use of both conformance testing and interoperability testing is of greater value.

- Must we always test for both conformance and interoperability? The answer is no in some cases. However, this decision is based on efficiency of the test and possible savings for all concerned in the testing effort – implementers and testers alike. It is always best to do both – yet if the error generator is sufficient enough in an interoperability test, it is highly likely one will achieve the same results as doing the additional conformance testing. Also as noted above, conformance testing in some non- eBusiness type software can become close to interoperability or maybe achieve interoperability because there is no 'other software'.

### 3. GLOSSARY

#### Definition: COMPOSITE RELATION - $R1 \circ R2$

Let  $R1$  be a relation from A to B,  $(a, b) \in R1$ , and let  $R2$  be a relation from B to C,  $(b, c) \in R2$ , . Then  $(a, c) \in R1 \circ R2$ , where  $a \in A$  and  $b \in B$ , and  $c \in C$ .

#### Definition: CONFORMANCE ENGINE APPLICATION

A conformance engine application is composed of 3 parts:

- a test administrator facility
- a specification mimic that implements at least the parts of the specification to be tested
- an error generator application that produces *error-conditions*, and has the ability to produce non-domain elements to test the *domain* boundaries. These non-domain elements could produce two types of errors: error-conditions or errors the applications do not handle programmatically correctly. We call these later ones *test-errors*.

#### Definition: CONFORMANCE ENGINE ERROR DEGREE

A conformance engine is said to be error free to degree N on the *specification*, if and only if, it has been tested against N implementations of the *specification* with all implementations producing random errors as they are tested.

#### Definition: CONFORMANCE TEST

A conformance test of an application shows that the application conforms to the *specification* by interacting with the **conformance engine application**.

#### Definition: CONFORMANCE TO A SPECIFICATION

An implementation of a *specification* is said to be conformant to the *specification*, IF and only IF, the input *domain*(x, y,..), and the output *range*(a, b,...) of the implementation meet the requirements of the *specification* and the relation,  $range = R(domain)$ , when  $R$  implements the requirements of the *specification*.

*This is a normal BLACKBOX arrangement with  $R$  as the BLACKBOX, the input being the domain and the output being the range. See Figure 1a.*

The dependant and independent variables of the *range* and *domain* may be Boolean, real, integer, documents, sets, etc. --that is, they may be composed of any length bit-stream.

#### Definition: ERROR-CONDITION

An *error-condition* is a condition in a program where the *domain* of R elicits a known *range*-element of type "error" or warning as the *specification* designates. This is not an error in testing or conformance. This is 'success' because the program is acting as the *specification* designates.

#### Definition: ERROR GENERATOR APPLICATION

An error generator application produces *error-conditions*, and has the ability to produce non-domain elements to test the *domain* boundaries.

#### Definition: FULL MATRIX INTEROPERABILITY TEST

A full matrix interoperability test for a set of applications built on a *peer-interoperable specification* shows the applications interact properly -- are peer-interoperable -- each with every other, in a full matrix manner as the *specification* states. Thus it must show that  $R2$  initiates and  $R1$  responds,  $R1(R2(domain))$ , and  $R1$  initiates and  $R2$  responds,  $R2(R1(domain))$ , properly and both are a subset of *domain* for every pair of applications, whose relations  $R1$  through  $Rn$  are within the test and an application responds to peer implementation  $R(R(domain))$ . See Figure 2 and Figure 1b.

### Definition: PEER-INTEROPERABLE SPECIFICATION

A *specification* is said to be peer-interoperable, IF and only IF, the input *domain*( $x, y, \dots$ ) and the output *range*( $a, b, \dots$ ) meet the requirements of the *specification*. It also requires that the relation,  $R$ , implements the requirements of the *specification* and *domain* is a superset ( $\supseteq$ ) or proper superset ( $\supset$ ) of  $R(R(\text{domain}))$ .

(The dependant and independent variables of the *range* and *domain* may be Boolean, real, integer, documents, sets, etc. (that is, they may be composed of any length bit-stream.)

### Definition: RELATION - $R$

Suppose  $R$  is a relation from  $A$  to  $B$ . Then  $R$  is a set of ordered pairs where each first element comes from  $A$  and each second element comes from  $B$ . That is, for each pair  $a \in A$  and  $b \in B$  then  $(a, b) \in R$  is read as “ $a$  is  $R$ -related to  $b$ ”. The domain of a relation  $R$  is the set of all first elements of the ordered pairs which belong to  $R$ . The range of  $R$  is the set of second elements.

### Definition: SPECIFICATION

A *specification* is a pre-test agreement among implementers of sufficient detail and exactness which allows evaluation of an implementation as to meeting the *specification*'s conditions.

**Note:** This definition covers profiling also. It also covers *specifications* that are not standards but are done when two or more companies decide to intercommunicate in a more ad hoc manner. Finally, it may cover all standards such as HTTP, on which, the *specification* is based. This is necessary because we often test a *specification* for conformance or IOP, yet do not test the supporting standards which may not be conformant in the implementations and could potentially cause a problem. For example, if using HTTP, we don't know the HTTP code to make sure that it is conformant to HTTP specifications or has been profiled correctly across all the implementations.

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### Definition: TEST CRITERIA

The test criteria are the detailed test plan based on the specification under test that is usually composed of many individual test cases.

### Definition: TEST-DOMAIN

*Test-domain* is normally a superset of *Domain* whose purpose is to verify that the relation  $R$  is rejecting non-*domain* input elements. (Note: In a well written *specification*, one would expect all *Test-domain* elements minus *domain* elements to produce **error-conditions** and not *test-errors*. However, in distributed applications, *test-errors* or **error-conditions** produced from outside events such as communication errors, communications interruptions do occur.)

### Definition: TEST-ERRORS

A **test-error** is when the *domain* of  $R$  elicits a condition, for which, there is no element in the *range* because it is undefined in the *specification* or because the application has not been designed properly.

### Definition: TESTING-EVENT-ERROR

Type II Errors in which the systems under test:

- Fail to identify a non-conformance error
- Agree that something is not a **test-error** when it actually is
- An error escaping thru the test regime for each test case

[<sup>1</sup>] *Schaum's Outlines: Discrete Mathematics*, 2<sup>nd</sup> ed., Lipschutz, S. and M. Lipson, p. 28, McGraw-Hill, 1997

[<sup>2</sup>] *Elementary Statistics*, 9<sup>th</sup> ed. Triola, M., p.381 Pearson Education, 2004

## Biography

As the chief executive officer and chief scientist for Drummond Group Inc. (DGI), Rik Drummond has led the company's technical and research strategies while steering DGI to constant growth and innovation. He is a widely respected authority in the eBusiness industry and has been a driving force in the technical standards bodies and vertical industry groups supporting B2B commerce.

DGI, a global leader in eBusiness and eGov software testing and certification, works with software vendors, industry associations, supply chains and the standards community by conducting interoperability and conformance testing, consulting, publishing related strategic research and developing vertical industry strategies. Founded in 1999, DGI has tested thousands of international software products. DGI's certified products are used in vertical industries such as automotive, consumer product goods, financial services, government, petroleum, pharmaceutical and retail.

Drummond previously served as chair of the Electric Industry's GridWise Architecture Council ([www.gridwiseac.org](http://www.gridwiseac.org)) in the USA, the chairperson for EDIINT Workgroup of IETF ([www.ietf.org](http://www.ietf.org)) which has produced several standards, and was the Workgroup leader for ebXML Messaging v1.0 under OASIS ([www.oasis-open.org](http://www.oasis-open.org)).

# Defining Common Information Model (CIM) Compliance

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**Keywords:** CIM Definition, CIM compliance, CIM profile, interoperability, integration readiness, architecture, utility domain

## Abstract

To prosper in a competitive market, utilities are forced to better integrate their systems and processes in order to reduce operating and maintenance costs as much as possible and to improve overall reliability. The Common Information Model (CIM) is designed to achieve easier interoperability between systems. However, the lack of a complete standard semantic model creates a major stumbling block for more effective and efficient integration. Since CIM is the most complete standard semantic model in utility industry, in order to promote and encourage broader use of CIM, explicit and practical rules for CIM compliant interoperability assessment are proposed here.

The idea of leveraging CIM as semantic model has been elaborated and emphasized in [5]. Reference [5] also recognizes a need for explicit CIM compliance rules. The purpose of this paper is to propose a practical and consistent approach for defining the IEC Common Information Model compliance types and levels relative to the different interoperability scenarios where CIM can be leveraged.

Two key types of CIM compliance are elaborated in more details, namely semantic and syntactic compliance at different compliance levels in the context of different interoperability and data usage patterns using several technologies such as Data Management (DM) solutions, Enterprise Service Bus (ESB) and Service-Oriented Architecture (SOA), Enterprise Information Integration (EII), Extract, Transform and Load (ETL), etc.

A formal definition of CIM (a mathematical formulation) is presented as a prelude to explicit CIM compliance rules for each applicable type and level.

## 1. INTRODUCTION

The Common Information Model (CIM) is a conceptual information model for describing business entities in electrical energy business domain including enterprise and

service provider environments. It provides a consistent definition and structure of data, using object-oriented techniques. The CIM includes expressions for common elements that must be clearly presented to management systems and applications like object classes, attributes, properties, and associations to name a few.

The CIM was originally developed as part of the EPRI CC-API project, and then later adopted by IEC TC57 as a standard, IEC 61970-301. IEC TC57 WG13 specified the use of XML and RDF Schema to represent a set of CIM core objects as the basis for exchanging Transmission Network Model data between applications. At the time, XML Schema (XSD) had not yet been adopted by W3C as a standard. IEC TC57 WG14 later specified the use of XSD to define message standards based on the CIM (the IEC 61968 series of standards).

## 2. INTEROPERABILITY AND INTEGRATION READINESS

Per Gartner [2] "Integration" is defined as the act or approach of making two of more independently designed things (systems, databases or processes) work together to achieve a common business objective. For practical reasons, integration activities within large enterprises are typically classified as data and application integration. The ultimate result of integration is the fact that all applications work seamlessly together in achieving the same business objective and that typically involves data exchanges and synchronization (data sharing) as well as process and activity coordination.

## 3. CIM USAGE PERSPECTIVE

The CIM as an information model can be used as a semantic vehicle to achieve full compatibility of data definitions and exchange of data between numerous applications across business areas and corporate boundaries. The CIM defines a standard and a common way of representing a variety of physical and abstract data related to the operation of electric utility organizations. For sometime it's been mostly known for its use in the area of transmission network modeling and simulation, but now with latest extensions, it also contains representations for data related to generation control,

scheduling, SCADA, distribution and market functions as well as business objects such as assets and documents. In order to enrich the business context around the existing model, CIM is being envisioned as ontology that defines business concepts, relationships and a set of rules in the utility business domain. It is designed to provide a way to access and manage data from multiple sources, facilitate understanding, and enable rapid use by software applications.

From an integrator perspective, the Common Information Model allows EAI/ESB [1, 3, 4], ETL, EII, BI, Modeling, Process and Data management technology solutions to work together in standard ways. All solutions share the same information model and common vocabulary.

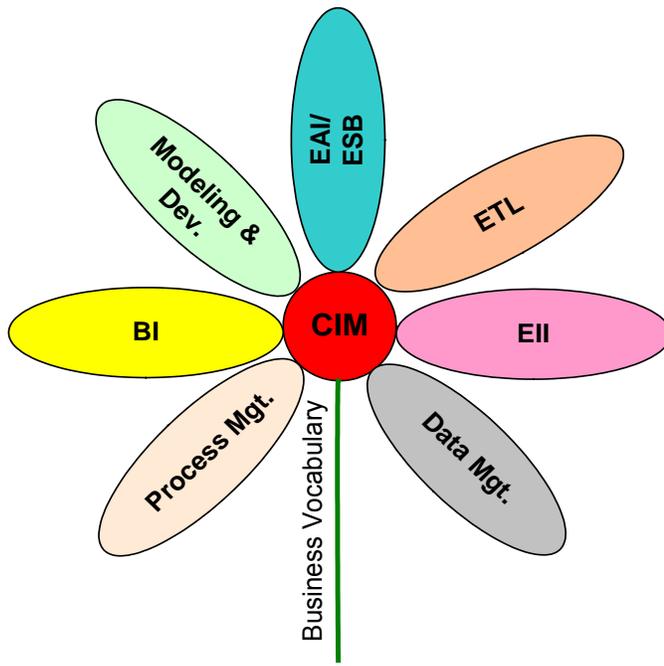


Figure 1: Role of CIM

In general, CIM facilitates common understanding within and beyond corporate boundaries.

CIM can be effectively leveraged in the following technology solutions (Figure 1) and interoperability scenarios:

- Enterprise Application Integrating (EAI) / Enterprise Service Bus (ESB) – provides basis for standard-based message payloads and data transformation (e.g. XSLTs) from and to CIM structures.
- Enterprise Information Integration (EII) – provides platform-independent logical model as well as mappings to underlying systems and federated queries.
- Extract, Transform and Load (ETL) – Generates data transformation workflows to convert data from a source

to a target data store using CIM as a logical intermediary.

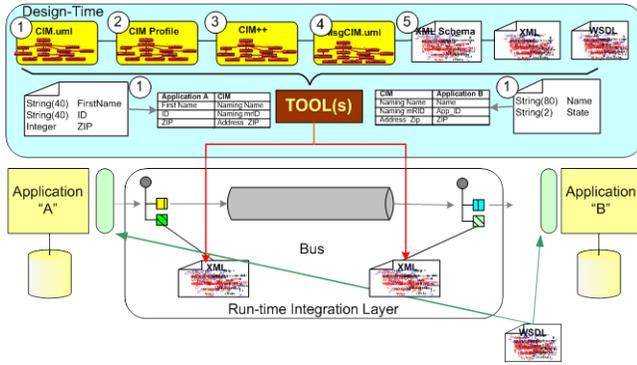
- Modeling and Development tools – Create / extent / profile models (e.g. interface model) using CIM structures
- Business Intelligence (BI) tools – Using CIM and Business Vocabulary (BV) to generate common business views
- Data Management solutions - provides platform-independent logical model as well as data exchange mappings from CIM-based payloads to underlying systems.
- Process Modeling – More effective process engineering leveraging CIM use cases and standard functional decomposition as well as standard data exchanges and BV.
- Composite Applications Framework – provides standard-based interoperability framework for linking technology and business components into functional assemblies.
- Network Model data exchanges - provides ability for multiple components (within the same organization or B2B) to exchange network models

### 3.1. Art of Integration

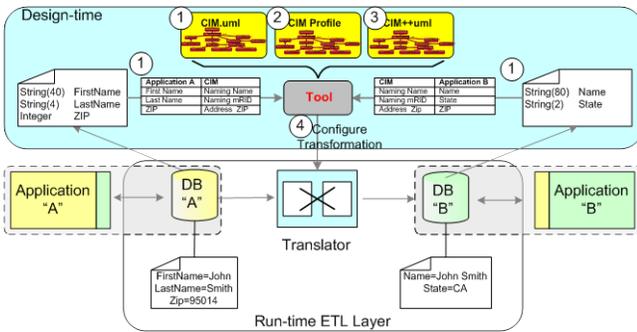
Large scale integration projects require a customized, very often innovative approach designed to achieve major business objectives on time. The key step in each integration project is data exchange analysis.

Data Exchange analysis is designed to identify what data each component would receive from upstream components as well as data it would provide to downstream components. This analysis also identifies all data mappings at data element level as well as all required transformation rules. This is much easier to achieve if all systems' data are mapped to a common information model or in other words if all components “talk” and understand CIM.

Figure 2 illustrates a CIM usage in an integration project where CIM was leveraged extensively. The design time semantic analysis started with CIM. CIM profile as a subset of CIM was created with only data elements required in the project. The CIM profile is then extended with required data elements that were not part of CIM Profile. Note also that those data elements were discovered during data exchange analysis. For Example 1, besides leveraging CIM as integration semantic model, CIM is also used for Web Services and message payloads design.



**Figure 2:** - Example 1 of CIM Usage – Web Service design  
 Figure 3 example described ETL pattern of data exchanges where CIM is leveraged as semantic intermediary to configure transformation rules.



**Figure 3:** - Example 2 of CIM Usage – ETL  
 These two examples are presented rather briefly just to illustrate how CIM can be leveraged in integration projects.

#### 4. CIM FORMAL DEFINITIONS

The CIM is seen as a conceptual information model consisting of entities, attributes (class fields), properties (in this context data type properties) and relationships. The CIM can be formally defined as follows:

##### Definition 1 – CIM Definition

A CIM is a 4-tuple:  $C = (E, A, P, R)$ , where:

- $E$  is set of Entities in CIM:  
 $E = \{e_i | 1 \leq i \leq n, e_i \in E\}$
- $A$  is set of Attributes in CIM:  
 $A = \{a_j | 1 \leq j \leq m, a_j \in A\}$
- $P$  is set of Properties in CIM  
 $P = \{p_k | 1 \leq k \leq o, p_k \in P\}$
- $R$  is set of Relationships in CIM  
 $R = \{r_l | 1 \leq l \leq q, r_l \in R\}$

- $n$  – number of entities in CIM
- $m$  – number of attributes in CIM
- $o$  – number of properties in CIM
- $q$  – number of relationships in CIM

##### Definition 2 – CIM Profile Definition

CIM profile is a subset of CIM and contains only entities, attributes, properties and relationships necessary to achieve required business objectives. CIM profile is defined formally as:

A CIM Profile is a 4-tuple:  $C_{pr} = (E_{pr}, A_{pr}, P_{pr}, R_{pr})$ , where:

- $E_{pr}$  is set of Entities in CIM Profile:  
 $\{e_i | 1 \leq i \leq n_{pr}, e_i \subset E\}$
- $A_{pr}$  is set of Attributes in CIM Profile:  
 $A_{pr} = \{a_j | 1 \leq j \leq m_{pr}, a_j \subset A\}$
- $P_{pr}$  is set of Properties in CIM Profile:  
 $P_{pr} = \{p_k | 1 \leq k \leq o_{pr}, p_k \subset P\}$
- $R_{pr}$  is set of Relationships in CIM Profile:  
 $R_{pr} = \{r_l | 1 \leq l \leq q_{pr}, r_l \subset R\}$
- $n_{pr}$  – number of entities in CIM profile  $\{n_{pr} < n\}$
- $m_{pr}$  – number of attributes in CIM profile  $\{m_{pr} < m\}$
- $o_{pr}$  – number of properties in CIM profile  $\{o_{pr} < o\}$
- $q_{pr}$  – number of relationships in CIM profile  $\{q_{pr} < q\}$

##### Definition 3 – Extended CIM Definition

Extended CIM is either CIM profile or CIM with additional entities, attributes, properties and relationships necessary to achieve required business objectives. Extended CIM is defined formally as:

An Extended CIM is a 4-tuple:  $C_{ex} = (E_{ex}, A_{ex}, P_{ex}, R_{ex})$ , where:

- $E_{ex}$  is set of Entities in extended CIM:  
 $E_{ex} = \{e_i | 1 \leq i \leq n_{ex}, e_i \in E_{ex}, E \subset E_{ex}\}$
- $A_{ex}$  is set of Attributes in extended CIM:  
 $A_{ex} = \{a_j | 1 \leq j \leq m_{ex}, a_j \in A_{ex}, A \subset A_{ex}\}$
- $P_{ex}$  is set of Properties in extended CIM:  
 $P_{ex} = \{p_k | 1 \leq k \leq o_{ex}, p_k \in P_{ex}, P \subset P_{ex}\}$
- $R_{ex}$  is set of Relationships in extended CIM:  
 $R_{ex} = \{r_l | 1 \leq l \leq q_{ex}, r_l \in R_{ex}, R \subset R_{ex}\}$

- $n_{ex}$  – number of entities in extended CIM {  $n_{ex} > n$  }
- $m_{ex}$  – number of attributes in extended CIM {  $m_{ex} > m$  }
- $o_{ex}$  – number of properties in extended CIM {  $o_{ex} > o$  }
- $q_{ex}$  – number of relationships in extended CIM {  $q_{ex} > q$  }

**Definition 4** – CIM Mapping / Transformation Definition

Transformation is defined as an operation / action required for mapping elements of CIM to elements of a model under consideration.

A simple mapping or transformation is defined as 3 - tuple:

$$T = (M, O, C)$$

where

- $T$  is set of mappings / transformations  
 $\{t_i | 1 \leq i \leq n_t, t \in T\}$
- $C$  is set of CIM elements
- $M$  is set of Model elements
- $O$  – set of operations (simple transformation / function or direct mapping) that maps elements of set  $M$  to elements of set  $C$

$O: M \rightarrow C$  where

$$\{m_j = o_i(c_k)\}$$

$$\{m_j | 1 \leq j \leq a_m, m_j \in M\}$$

$$\{c_k | 1 \leq k \leq a_c, c_k \in C, \}$$

$$\{o_i | 1 \leq i \leq n_m, o_i \in O, a_m \leq a_c\}$$

- $a_m$  – number of attributes in  $M$
- $a_c$  – number of attributes in CIM
- $o$  – number of operations that transform / map model data elements to CIM

**Definition 5** – CIM compliance indicator for a model is defined as percentage of model data elements mapped to CIM.

CIM compliance indicator is defined as

$$t\% = a_t / a_m * 100$$

where

- $t\%$  - percentage of elements mapped to CIM
- $a_t$  – total number of data elements from model  $M$  mapped to CIM

- $a_m$  – number of applicable attributes in model  $M$

**Definition 6** – CIM compliance indicator for multiple models (e.g. sender/source and receiver/target) is defined as percentage of model data elements that map to each other ( $M_1 \rightarrow M_2$ ) and to CIM.

CIM compliance indicator for multiple  $m$  models is defined as

$$t_m\% = a_t / a_n * 100$$

where

- $t_m\%$ - percentage of elements mapped to CIM
- $a_t$  – total number of data elements from model  $M_1, M_2 \dots M_n$  that map to each other and to CIM
- $a_n$  – number of applicable attributes in models  $M_1, M_2 \dots M_n$

**Definition 7** – CIM compliance indicator for multiple models (e.g. sender/source and receiver/target) is defined as percentage of model data elements that map to each other ( $M_1 \rightarrow M_2$ ) and to CIM.

CIM compliance indicator  $s$  for multiple  $m$  models is defined as

$$s_m\% = a_s / a_n * 100$$

where

- $s_m\%$  - percentage of elements mapped to CIM
- $a_s$  – total number of data elements from model  $M_1, M_2 \dots M_n$  that map to each other and to CIM at entity, attribute, property and relationship level.
- $a_n$  – number of applicable attributes in models  $M_1, M_2 \dots M_n$

Definition 7 implies that message payloads are derived from CIM.

## 5. COMPLIANCE DEFINITIONS AND RULES

Interoperability between systems is much easier to achieve if domain models of all integrated components comply with a standard model such as CIM. For this consideration and in this context, two key types of CIM compliance are recognized semantic and syntactic compliance.

### 5.1. Semantic Compliance

The following semantic compliance rule is proposed to assess CIM compliance level of an information model:

**Compliance Rule 1** - A necessary condition for CIM semantic compliance is the ability to map directly or using a simple translation, data elements of an information model to the respective attributes of the CIM.

**Rule** – Supposing Definition 4 and according to Definition 5, CIM Compliance Levels are

If  $10 < t_{\%} < 20$  then  $CL = 1$   
 Else if  $20 < t_{\%} < 30$  then  $CL = 2$   
 Else if  $30 < t_{\%} < 40$  then  $CL = 3$   
 Else if  $40 < t_{\%} < 50$  then  $CL = 4$   
 Else if  $50 < t_{\%} < 60$  then  $CL = 5$   
 Else if  $60 < t_{\%} < 70$  then  $CL = 6$   
 Else if  $70 < t_{\%} < 80$  then  $CL = 7$   
 Else if  $80 < t_{\%} < 90$  then  $CL = 8$   
 Else if  $90 < t_{\%} < 99$  then  $CL = 9$   
 Else if  $t_{\%} = 100\%$  then  $CL = 10$

where

- $CL$  – CIM compliance Level

The Rule1 should be used mainly to assess semantic CIM compliance level. Per rule, a semantic compliance can be achieved at several levels depending on percentage of data elements mapped to CIM (e.g. Level 1 - 5-10%, Level 2 - 10-20%, Level 3 20-30%, Level 4 40-50%, Level 5 - 50-60%, Level 6 60-70%, Level 7 70-80%, Level 8 80-90%, Level 9 90-99% and Level 10 - 100%). Using the Compliance Rule 1, the information model M should be considered as CIM Compliant at some level if sufficient number (e.g. for Level 4 between 40 and 50%) of data elements has corresponding CIM data elements (e.g. entity/data element Organization.type in an EIM can be mapped to entity/data element Company.companyType in CIM ). This would ensure that the same logical concepts for data elements in the model under consideration are equivalent to those in CIM.

### 5.1.1. Interoperability (Message Payloads / Interfaces / Data Streams) CIM Compliance

This section defines compliance rules at data exchange / interface level.

**Compliance Rule 2** - A necessary condition for CIM compliant semantic interoperability between two systems is the existence of mapping schema or translation function that maps data elements of the domain models of both systems (sender/source and receiver/target) to the respective attributes of CIM.

**Rule** – Supposing Definition 4 and according to Definition 6, CIM Compliance Levels are

If  $10 < t_{m\%} < 20$  then  $CL = 1$   
 Else if  $20 < t_{m\%} < 30$  then  $CL = 2$

Else if  $30 < t_{m\%} < 40$  then  $CL = 3$   
 Else if  $40 < t_{m\%} < 50$  then  $CL = 4$   
 Else if  $50 < t_{m\%} < 60$  then  $CL = 5$   
 Else if  $60 < t_{m\%} < 70$  then  $CL = 6$   
 Else if  $70 < t_{m\%} < 80$  then  $CL = 7$   
 Else if  $80 < t_{m\%} < 90$  then  $CL = 8$   
 Else if  $90 < t_{m\%} < 99$  then  $CL = 9$   
 Else if  $t_{m\%} = 100\%$  then  $CL = 10$

where

- $CL$  – CIM compliance Level

This ensures that the exchanged information has the same meaning for both systems (sender and receiver). The semantic compliance can be achieved at several levels depending on percentage of data elements mapped to CIM (e.g. Level 1 - 5-10%, Level 2 -10-20%, Level 3 20-30%, Level 4 40-50%, Level 5 - 50-60%, Level 6 60-70%, Level 7 70-80%, Level 8 80-90%, Level 9 90-99% and Level 10 - 100%).

### 5.2. Syntactic Compliance

Another type of CIM compliant data exchanges deals with syntactic interoperability. The syntactic interoperability is seen as grammar that conveys semantics and structure / format of data exchanges such as messages' payloads or data streams.

**Compliance Rule 3** - A necessary condition for CIM compliant syntactic interoperability between two systems is the existence of semantically compliant sender and receiver as well as when both systems (sender and receiver) can process message structure/payload derived from CIM.

**Rule** – Supposing Definition 4 and according to Definition 7, CIM Compliance Levels are

If  $10 < s_{m\%} < 20$  then  $CL = 1$   
 Else if  $20 < s_{m\%} < 30$  then  $CL = 2$   
 Else if  $30 < s_{m\%} < 40$  then  $CL = 3$   
 Else if  $40 < s_{m\%} < 50$  then  $CL = 4$   
 Else if  $50 < s_{m\%} < 60$  then  $CL = 5$   
 Else if  $60 < s_{m\%} < 70$  then  $CL = 6$   
 Else if  $70 < s_{m\%} < 80$  then  $CL = 7$   
 Else if  $80 < s_{m\%} < 90$  then  $CL = 8$   
 Else if  $90 < s_{m\%} < 99$  then  $CL = 9$   
 Else if  $s_{m\%} = 100\%$  then  $CL = 10$

where

- *CL – CIM compliance Level*

Using message structure/payload derived from CIM, enables so-called direct access to the payload by participating systems while payload just based on CIM requires a clearly defined transformation function / rules. Note that both approaches can be combined in a single payload.

The syntactic compliance can be achieved at several levels depending on percentage of data elements in payload directly derived from CIM or in other words those that facilitate 'direct access' (e.g. Level 1 - 5-10%, Level 2 -10-20%, Level 3 20-30%, Level 4 40-50%, Level 5 - 50-60%, Level 6 60-70%, Level 7 70-80%, Level 8 80-90%, Level 9 90-99% and Level 10 - 100%).

### 6. INTEGRATION READINESS ASSESSMENT

Integration readiness is seen as a component's ability to interact with other components in an integrated environment. The integration readiness can be assessed by complexity level or effort required to enable a component to exchange information with other components. Experience on large scale integration projects demonstrates that inadequate component' integration readiness results often in significant project delays. Organizations undertaking large scale integration projects are often forced to deal with large number of non-standardized, non-CIM compliant data exchanges resulting in project delays simply because of absence of semantic and syntactic standard compliance rules to assess integration readiness before project starts. Therefore it is extremely important to measure integration readiness of all components at the component selection time. The proposed CIM semantic and syntactic compliance rules are strongly recommended to measure integration readiness of each component.

**Table 1:** Complexity of Integration vs. Compliance Levels

Integration Complexity	Description	Semantic Compliance Level				Syntactic Compliance Level			
		2	4	7	10	2	4	7	10
High	No SM, No EPs	✓	✓			✓	✓		
Med.High	No SM, Some EPs	✓	✓			✓	✓		
Medium	SM, Some EPs			✓			✓		
Med.Low	SM, EPs			✓				✓	
Low	SM and standard based EPs			✓	✓			✓	✓
Zero Coding Effort*	Plug & Play				✓				✓
Zero effort	True Plug & Play								✓

SM – Semantic Model; EP- End point (e.g Interface, Web Service, input/output staging tables, shared folder)

\* - Configuration Effort

The empirically based Table 1 shows strong relationships between complexity of integration and integration readiness expressed in terms of semantic and syntactic compliance levels to a common information model.

Note that higher compliance levels decreases chances of projects' delays and leads to more effective as well as less expensive integration.

### 7. CONCLUSION

CIM Semantic and Syntactic compliance rules are proposed in this paper. CIM formal definitions are presented as well to provide foundation for clear description of compliance rules. The proposed rules can be used to assess components' integration readiness. Solution providers are strongly encouraged to evaluate integration readiness of their products and use that as a competitive advantage especially for components that would interact with other systems and applications. The proposed rules should encourage non-product suppliers to develop services and tools for CIM compliance level certifications.

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### Biography

Dr. Stipe Fustar has over twenty five years of experience in the electric utility industry including architecture and integration technical consulting, project/team management, development, data modeling, system design and quality assurance. He has a deep understanding of all aspects on electric utility industry covering a broad range of energy, distribution and market management services as well as, asset management, smart grid, AMI, AM/FM/GIS technology, data modeling, SCADA, and system integration and design. He provides a unique blend of electric utility industry expertise and strong IT Architecture and

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# Scenarios for Consuming Standardized Automated Demand Response Signals

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## Abstract

Automated Demand Response (DR) programs require that Utility/ISO's deliver DR signals to participants via a machine to machine communications channel. Typically these DR signals constitute business logic information (e.g. prices and reliability/shed levels) as opposed to commands to control specific loads in the facility. At some point in the chain from the Utility/ISO to the loads in a facility, the business level information sent by the Utility/ISO must be processed and used to execute a DR strategy for the facility. This paper explores the various scenarios and types of participants that may utilize DR signals from the Utility/ISO. Specifically it explores scenarios ranging from single end user facility, to third party facility managers and DR Aggregators. In each of these scenarios it is pointed out where the DR signal sent from the Utility/ISO is processed and turned into the specific load control commands that are part of a DR strategy for a facility. The information in these signals is discussed. In some cases the DR strategy will be completely embedded in the facility while in others it may be centralized at a third party (e.g. Aggregator) and part of an aggregated set of facilities. This paper also discusses the pros and cons of the various scenarios and discusses how the Utility/ISO can use an open standardized method (e.g. Open Automated Demand Response Communication Standards) for delivering DR signals that will promote interoperability and insure that the widest range of end user facilities can participate in DR programs regardless of which scenario they belong to.

## 1. AUTOMATED DEMAND RESPONSE SIGNALS

Demand Response (DR) programs can take many forms. DR programs differ from normal rates and tariffs in that they are designed to allow for the Utility/ISO to take specific actions to influence the load profiles of facilities that participate in the DR programs at peak consumption times on the grid. These peak consumption periods may cause critical grid reliability issues which must be addressed, but they may also trigger economic factors wherein the price of electricity reaches critical levels which may be ameliorated by reducing the overall consumption on the grid during those periods. These critical periods in which the Utility/ISO needs to influence the load profile of a Facility are referred to as DR Events. Much of DR today is managed as a set of programs in which the participants enter into some contractual agreement about how they will get compensated by participating in the DR Events. As the real time pricing markets evolve the notion of being compensated during a specific event period may get replaced with a purely price responsive mechanism that does not require that the facility be explicitly notified that a DR Event per se is occurring.

The manner in which the Utility/ISO influences the load profile of a facility is to send out a so called DR signal which is specific to the DR Event. The nature of the information in the DR signal varies widely depending upon the DR program. In some cases the DR signals contains business level information such as the following:

- Prices
- Shed levels
- Grid reliability related information

- Baselines

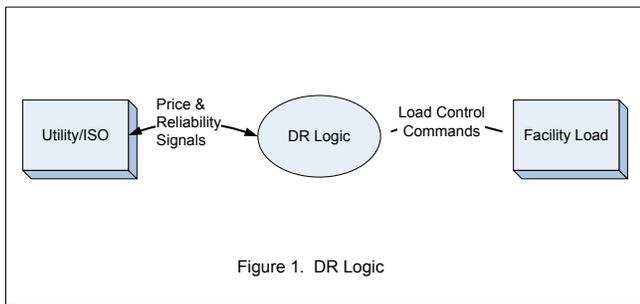
In other cases the DR signal may contain information that is related to controlling loads such as:

- Specific device commands such as a command to turn on or off a specific device in the facility
- Generalized device state information such as temperature set points for HVAC systems.
- Desired facility state information such as “low occupancy mode”

This paper is focused on so called Automated DR and therefore by definition the DR signals that are sent out by the Utility/ISO are utilized by machines that enable the response to the DR signals to occur in an automated fashion.

Ultimately it is the loads within the facility that are affected during DR Events, but the individual facilities are not the only parties that may utilize DR signals and act on them. In some cases there may be third party intermediaries (e.g. Aggregators) that may play a role in consuming a DR signal and determining how a facility responds to it. There are a number of possible such intermediaries that may play a role in this process and these will be covered in more detail in a subsequent section of this paper.

Regardless of whether the individual facility is consuming the DR signal or some intermediary on their behalf, there is a fundamental process which occurs that transforms the business level information that originally triggered the DR Event into a set of load control commands that affect the actual loads. This is depicted in Figure 1.



The process of making this conversion is referred to as “DR Logic”. A simple example of DR Logic may be the implementation of a rule such as:

If the electricity price is greater than \$0.25 then set thermostat from 72 to 78 °F and turn off lights in loading dock.

The DR Logic may be simple as shown above or it may be complex and include such things as pre-cooling before the DR Event or possibly involve the modification of a complex industrial process. In short, the DR Logic represents the points in the system where business level information related to a DR Event is converted into control level information that can be used to control specific loads in a facility.

This paper is focused on where this DR Logic resides and how it effects interoperability. In general the DR Logic may reside anywhere from the Utility/ISO to a third party intermediary to the facility and even the load itself.

It should be noted that for any DR program or dynamic tariffs there are many potential interactions between the Utility/ISO and the DR participants besides just sending/receiving a DR signal. These interactions may include the following:

- Collection of information prior to the DR event to allow the Utility/ISO to predict the expected load response to a DR signal.
- Monitoring of loads during DR Events to determine how participants are responding and to insure that they are behaving as expected.
- Collection of information after the end of the DR event to allow post mortem activities such as financial settlement between the Utility/ISO and the parties that participated in the DR event.

While each of the above described interactions are worthy of consideration and may play a crucial role in any DR program this paper only focuses on the delivery of DR signals which is the one interaction that is shared by all automated DR programs.

## 2. FACILITIES AND DR STRATEGIES

In general the term facility is used somewhat loosely and refers to any location in which there are loads that may be influenced by DR Events. These can include residential, commercial and industrial facilities. Furthermore the facilities may be as simple as a single building or as complex as a campus with multiple buildings perhaps controlled by a centralized control system. This paper focuses more on commercial and industrial facilities where there is a well established marketplace of control systems that are already deployed and available to be used to control loads for the purposes of automated DR. This does not preclude the same principles and concepts presented in this paper from being applied to the residential space.

A simple generalized diagram of a facility is shown in Figure 2.

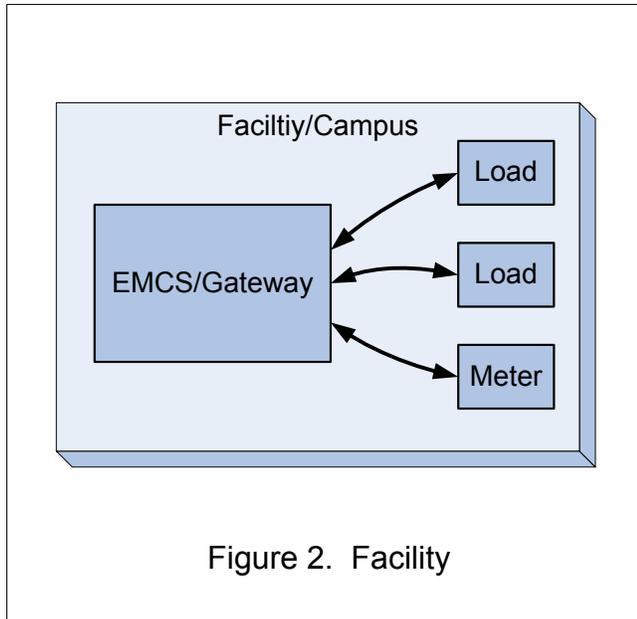


Figure 2. Facility

Regardless of whether a facility is a single building or a campus, for the purposes of this paper all facilities share the following elements:

- Loads which may be controlled in some automated fashion. These loads must have the ability to either receive load control commands or a DR signal directly. This implies that it has some means to communicate as well as control the load.
- Metering which can be used to measure the consumption of the facility.
- An Energy Management Control System (EMCS) or a gateway. Typically for larger commercial and industrial facilities there is an existing control system which utilizes some sort of centralized controller that is networked to a variety of load controls for the purpose of managing the operations of the facility. The centralized controller can be used as an EMCS for the purposes of DR and used to implement the DR Logic. In some cases there may simply be a gateway that allows DR signals or load control commands from external sources to reach the loads.

The types of loads that are used for the purposes of responding to DR Events vary depending upon the type of facility. In the case of commercial facilities it is typically heating, ventilation or air-conditioning (HVAC) and lighting loads while in the case of industrial facilities it

depends on the activities at the plant and can include peripheral equipment or primary process systems..

In addition to the loads being controlled, there is a so called DR strategy that is employed for each facility. Strategies vary widely depending upon the facility and range from direct load shedding during the event to load shifting as is used sometimes in the case of pre-cooling buildings. This paper does not focus on the strategies themselves, but instead focuses on the architecture for implementing the DR Logic which embodies the strategies.

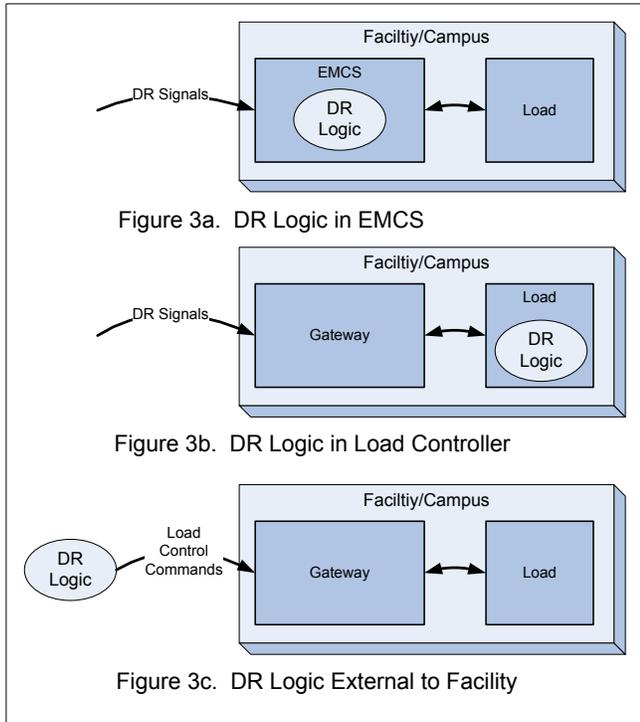
Figure 3 shows three different scenarios of where the DR Logic is implemented with respect to the facility where the loads are controlled.

In case 3a the DR Logic is encapsulated within the EMCS system of the Facility. This means that the DR signal containing the business level information is translated into load control commands by the EMCS which are transmitted to the various loads in the facility. The benefit of this approach is that the EMCS can implement system wide logic for the entire facility.

In scenario 3b there is a gateway that transmits the DR signal containing the business level information directly to the load which has a controller that implements the DR Logic that translates the information in the Dr signal into a device state. The down side of this approach is that there is no centralized facility level DR Logic.

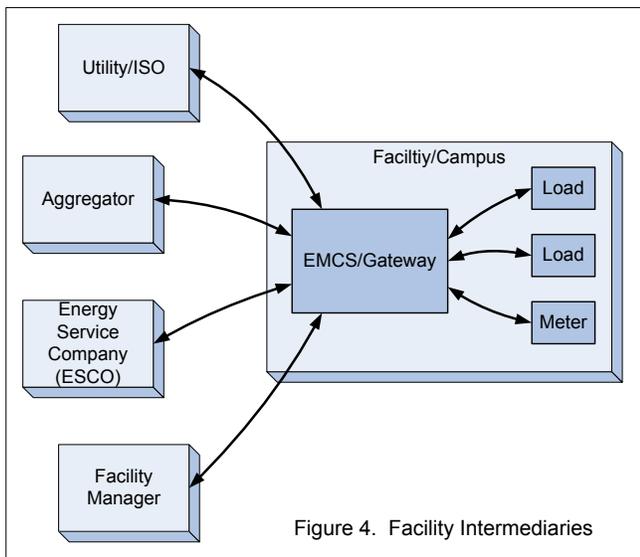
In scenario 3c the DR Logic is implemented at some entity outside the facility like the Utility/ISO, or some intermediary like an Aggregator. The DR Logic translates the business level information to load control commands and transmits these to the facility.

The important thing to note in Figure 3 is that the nature of the signals sent to the facility is dictated by where the DR Logic is implemented. In cases 3a and 3b a DR signal containing business level information (i.e. prices or shed levels) may be sent to the facility while in the case of 3c load control commands are sent. For the purposes of this paper 3a and 3b are considered equivalent since they both involve the same type of DR signal being sent to the facility.



### 3. THIRD PARTY INTERMEDIARIES

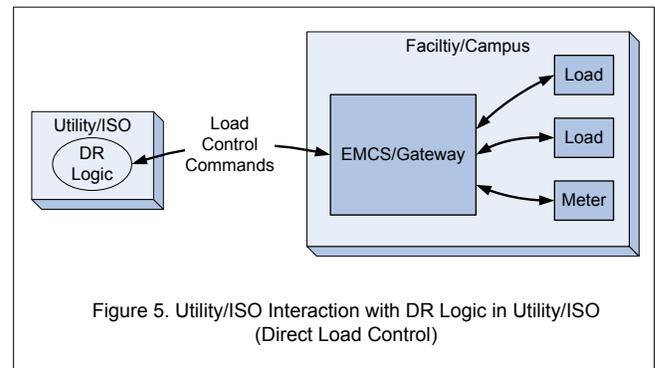
There are a number of organizations that may send signals to the facility and play a role, either directly or indirectly, in how the loads within a facility are ultimately controlled in response to a DR Event. Each of these parties are depicted in Figure 4 and discussed in more detail below.



The categories of intermediaries are meant to highlight differences between the type of business relationships the intermediaries have with the Utility/ISO and the end use facility. It is that relationship that dictates how the intermediary will try to influence the load profiles of a facility and thus where they may implement the DR Logic. Each of the entities described below have different motivations for controlling the loads within a facility and thus may take different approaches in both how and where the DR Logic for a facility is implemented. As we saw in the previous section, this may have an impact on the nature of the signals received by the facility. It should be noted that the discussion below for each category of intermediary is meant to give a prototypical scenario and is not meant to imply that all intermediaries of that type operate in the manner described.

#### 3.1. Utility/ISO

The Utility/ISO is one example of an organization that is the source of DR Event signals. In some DR programs the Utility/ISO performs what is called Direct Load Control as shown in Figure 5.



Direct Load Control essentially means that the DR Logic is implemented at the Utility/ISO and DR signals are sent to the facility which results in specific loads being controlled in a fairly specific fashion. The advantages of Direct Load Control are that it can result in a predictable response. The down side is that there is little or no flexibility in the load response and there is little or no customer choice in how the facility responds. Furthermore even if there were a standardized way to send load control signals to the facility it would not alleviate the need for the Utility to maintain a model for the loads in each facility and how they are to be controlled. In order to make that feasible the Utility/ISO can only deal with fairly simple and fixed types of loads.

A more flexible approach that allows a wider range of facilities and loads to participate is for the Utility/ISO to send a DR signal that contains business level information (i.e. price or reliability information). These signals allow a facility manager to choose how to implement the DR Logic that determines how the loads will respond. This is depicted

in Figure 6. The advantage of this approach is that the Utility/ISO can publish the DR signals using business logic that directly relates to the conditions on the grid that define the DR Event period. Since it doesn't need to control specific loads it can do this in a fairly standardized fashion and allow the facility to decide how its loads will respond to this information.

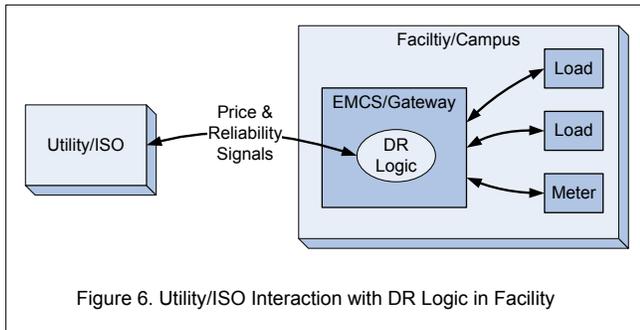


Figure 6. Utility/ISO Interaction with DR Logic in Facility

### 3.2. Aggregator

An Aggregator is a third party entity whose objective is to aggregate the loads of multiple facilities from different customers and have them behave as a single load to the Utility/ISO as depicted in Figure 7. They can receive standard business level DR signals from the Utility and then implement some sort of aggregated DR Logic across all the facilities in their portfolios. Since their objective is to spread the DR response among several different facilities in a manner which best suits their business objectives, it is not necessarily in their best interest to simply pass on the DR signal from the Utility/ISO directly on to their customers. They may instead either pass on some modified form of the general DR signal or in many cases perform direct load control with their customers.

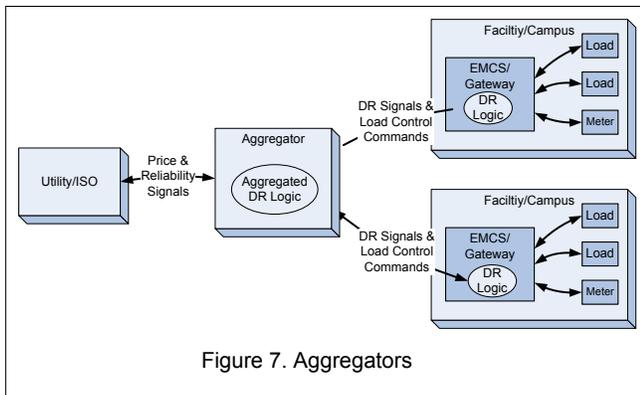


Figure 7. Aggregators

If the aggregator is performing direct load control then clearly the signals they send to the facilities will not be the same form as the DR signals they receive from the Utility/ISO. On the other hand if they pass on price and reliability signals much like they might receive from the Utility/ISO then the DR signal sent to the facilities may

have the same form, but may differ in the content depending upon how the aggregated DR Logic determines a specific facility should respond.

### 3.3. Energy Service Company (ESCO)

ESCO's provide a broad category of services to facilities, all centered on managing some aspect of the energy consumption of the facility. As shown in figure 8 they can act as an intermediary to receive standard business level DR signals from the Utility/ISO and use that information to manage facilities energy consumption. Their objectives are different from Aggregators in that they are more interested in load shaping (or load management at an individual facility while Aggregators are interested in delivering DR across multiple facilities.. Because of this difference they will either perform direct load control on the facilities or simply pass on the DR signal that was received from the Utility/ISO. It is unlikely they would modify the signal the way an Aggregator might since they are not trying to aggregate loads.

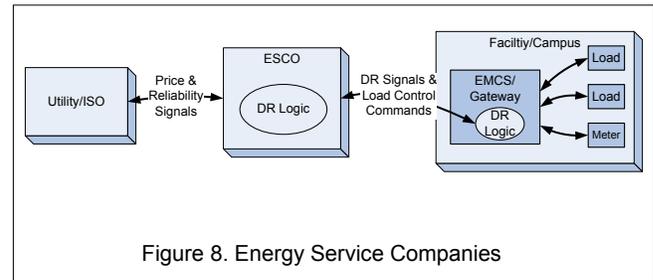


Figure 8. Energy Service Companies

### 3.4. Remote Facility Energy and Asset Manager

As shown in Figure 9 a Remote Facility Energy and Asset Manager can be a remote owner or a third party controls or service company that may be an intermediary between the Utility/ISO and the facility.

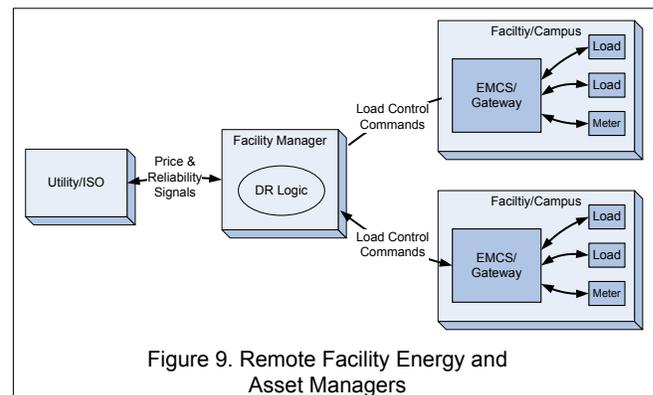


Figure 9. Remote Facility Energy and Asset Managers

They manage operational aspects of a facility from a control system point of view. Big box retail and chain businesses with many geographically dispersed facilities will hire these types of entities to manager all their facilities. Managing

energy consumption would be one of the operational aspects of a facility that would be under the responsibility of a Facility Manager entity. They are focused on the response of individual facilities and are typically not concerned with aggregating loads.

They typically manage all the controls of a facility from a centralized location and as such the nature of the signals they would most likely send to the facility would be of the form of load control commands. In this scenario the DR Logic for a particular facility would therefore be implemented at the Facility Manager site and not within the facility.

#### 4. ROLE OF STANDARDS FOR DR SIGNALS

From an industry wide interoperability perspective perhaps the most desirable form of a DR signals are for the Utility/ISO to publish a set of standardized signals that contains business level information such as prices and reliability information. A standardized DR signal of this type can allow all of the various participants and intermediaries outlined in section 3 to utilize the DR signals from any Utility/ISO. The fact that the DR signals contains business level information as opposed to direct load control commands allows for a wider range of participants to utilize the signals and gives them more flexibility in determining how they will respond. This is crucial in satisfying the requirement for “customer choice” in DR programs.

An example of one such possible standard for this type of DR signaling is that presented in the proposed OpenADR standards under development by the Demand Response Research Center of Lawrence Berkeley National Laboratory.

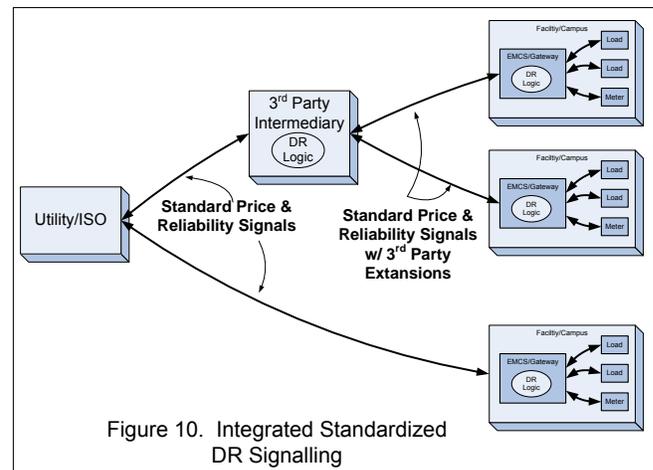
As outlined in section 3.1 there is a need in some use cases for the Utility/ISO to communicate standardized DR signals directly to a facility. Therefore, there is also a need for EMCS/controls vendors to adopt a common DR signaling standard so they may participate in these type of programs.

In many of the scenarios outlined in section 3 there are legitimate use cases where it is necessary to perform direct load control between the intermediary and the facility. In those cases the DR Logic is implemented within the intermediary and translated into the necessary load control commands sent to the facility. It is also important to note that in some cases the intermediary is not sending direct load control commands, but instead sending the same type of business level information that might be found in the DR signal that was originally sent from the Utility/ISO. In these cases the same DR signal standard that was used by the Utility/ISO to originally publish the DR signal could be used to send the DR signal to the facility by the intermediary. This would allow the controls vendors to leverage the same development money they spent to receive

the DR signals directly from the Utility/ISO to also receive them from intermediaries.

It is also important to note that in many cases the Utility/ISO will pay facilities large sums of money to enable them to participate in their DR programs and as such they would like to make sure that they are not creating so called stranded assets by enabling a proprietary infrastructure such as might be used by an Aggregator.

Figure 10 shows an architecture wherein standardized DR signals may be used in conjunction with the proprietary infrastructures of various intermediaries. In essence the objective is that whenever a facility is utilizing a DR signal that contains the same type of business level information that was originally published by the Utility/ISO they should use the same standard that was used by the Utility/ISO for the signals they publish regardless of whether that signal is being sent to facility from the Utility/ISO or an intermediary. This allows controls companies to build products that can participate in the widest range of DR programs and avoids stranded assets.



It should be noted that this does not preclude the intermediaries from implementing some sort of proprietary signaling to satisfy their own business objectives and technologies. The proposed OpenADR signaling standard allows for just these sorts of proprietary extensions.

#### 5. NATURE OF STANDARD DR SIGNALS

In this section we start with the assumption that the DR Signals that are being consumed by the various participants should contain business level information as opposed to direct load control commands as described in previous sections of this paper. This gives the maximum amount of flexibility to the participants that are consuming the DR signals. This type of information also better reflects the conditions on the grid that caused the DR Event to occur.

Furthermore since this paper focuses on Automated DR it should be noted that the DR signals are consumed by other computers, automation systems, and possibly end device load controllers. That dictates that the DR signal satisfy the following requirements:

- It should use standardized forms of representation (i.e. XML) to allow the widest range of existing development tools to be used to program the devices consuming the signals.
- The schema used to encode the information in the DR signal should be simple enough to allow lower end devices to process it.
- The complexity of the information should be such that simple rules can be devised by non-IT professionals (i.e. facility managers) to allow the DR Logic to be specified.
- The DR signal should be designed such that it can be delivered using widely deployed networking infrastructures such as IP networks and Web Services. Where applicable it should also comply with existing end device communications standards such as BACnet, OPC, oBIX, IETF, etc. This will allow for the widest range of end devices to consume the DR signal.
- The DR signal should be designed so that it can be delivered in a secure and non-repudiated fashion.

The above are cross cutting issues that define the constraints on how the DR signal is represented, independent of the type of information contained in the DR signal.

In general a standard DR signal should contain the following categories of information:

1. **DR Event information.** This is the actual business level information that is related to the DR Event. As already described, the nature of this information is dependent upon the DR program and how it is being managed and includes many different types of information. In some cases it may be prices and in other cases it may be shed levels, among other things. A standardized DR Signal needs to be able to accommodate the different types of information that may be used.
2. **Schedule of DR Event and business information.** This is a date and time that specifies when the DR Event is occurring and when the information related to the DR Event is valid. It may be as simple as a single calendar event or it may be a more complicated schedule which specifies when different pieces of information are valid. An example might be a schedule of prices wherein

different time slots during the DR Event period represent different prices.

3. **Ancillary information.** This is information that may aid the DR Logic in determining how best to respond to a DR Event. An example of this type of information includes grid reliability, source of energy (i.e. green power), etc.
4. **Intermediary specific information.** This allows for third party intermediaries to embed information within the DR signal that may be used to satisfy their specific objectives as outlined above.
5. **Simplified DR Event representation.** This is an alternative (i.e. simplified) representation of the DR Event information that allows a wider range of automation systems and load controllers to consume DR Events and respond to them.

With regards to item 1, a standardized DR signal should be harmonized with other standards (e.g. IEC 61850) that may also be standardizing the same types of information. An example is price information for which there currently does not exist a widely adopted standard, but when one is designed it should be utilized.

With regard to item 2, it is commonly recognized that there is a need for a standardized representation of schedules other than for the purposes of DR. Standards such as iCAL could play a role in defining the schedules in DR signals.

With regard to item 4, this paper identifies legitimate business reasons why third party intermediaries may want to control facilities in some proprietary fashion. Nonetheless there are other use cases that require the facilities to receive standardized DR signals directly from the Utility/ISO. Thus the vendors of control systems may be faced with investing development dollars into multiple means of receiving DR signals. A rational approach to minimizing this problem is to adopt standardized DR signals that everyone can adopt while allowing for the signals to be augmented in some fashion so that they can be used to satisfy the particular needs of some third party intermediary.

With regard to item 5, the type and complexity of the information sent as part of a DR signal can be quite varied and complex. Although this will allow a wide range of responses it also makes the task of consuming the DR signal quite complex. This is difficult to do for most existing automation systems and load controllers. Therefore also having a simplified representation of the DR Event can simplify the task of consuming the DR signals for these devices. Work at the Demand Response Research Center of Lawrence Berkeley National Laboratory has demonstrated that using a simple shed level representation

such as “moderate” and “high” can be effectively used to allow the controllers within facilities to respond to DR Events without having to parse and interpret much more complicated information such as price schedules. The more complex information (i.e. prices) that are part of the DR signal can be mapped to these simple levels prior to the signal being sent to the facility. Having both a more complex and simple representation of the information within the DR signals allows the maximum range of devices and systems to respond to the DR signal.

All the requirements given above formed the basis for the specification of the DR signal in the proposed OpenADR standard..

## 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 plans, manages, conducts and disseminates DR research for the California Energy Commission. Ms. Piette has a BA in Physical Science and a MS Degree in Mechanical Engineering from UC Berkeley and a Licentiate from the Chalmers University of Technology in Gothenburg, Sweden.

# Using the Intelligrid Methodology to Support Development of a Smart Grid Roadmap

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**Keywords:** Smart Grid, Use Cases, Requirements, Information Repository

## Abstract

Many electric utilities are in the process of evaluating how advancements in communications and information management technologies can be applied to enhance the operation and management of the power system infrastructure. This is the heart of the smart grid development. These technologies provide the foundation for many advanced applications that will make the grid more efficient and reliable, as well as enabling a wide range of customer services and benefits. The development and application of communication and information management technologies must be planned carefully based on corporate objectives, business cases, and existing infrastructure. This paper describes a roadmap process that can be applied to optimize the deployment of smart grid technologies using a structured process that has proven very successful.

## BACKGROUND

The power system of the future will incorporate advanced monitoring and control systems that will improve operations and system reliability. These advanced controls will integrate applications from transmission energy management systems to control of customer appliances and distributed generation. There are substantial investments in the communications and information infrastructures that will be needed to support this smart grid. A structured roadmap development process can help assure that the requirements of the future smart grid will be met by the investments in an integrated grid communications and information infrastructure.

The Intelligrid program at the Electric Power Research Institute (EPRI) developed a structured methodology for defining the requirements of advanced power system applications and technologies that is now published as an IEC Publicly Available Specification (PAS) [1]. The methodology (Figure 1) involves the development of use cases for applications that will help define the requirements for the smart grid infrastructure. By combining the requirements of a number of critical applications, overall requirements for the infrastructure can be derived. The roadmap development process involves developing the plans for migrating from the

existing infrastructure to the technologies and systems defined using the methodology.

This methodology has been used with a number of utilities to help define the requirements and infrastructure for the smart grid and the roadmap for achieving the vision. Examples of utilities that have used the process include Southern California Edison, FirstEnergy, Salt River Project, Duke Energy, Tennessee Valley Authority, New York Power Authority, Entergy, Consumers Energy, EDF (France), and CEMIG (Brazil). The result of these efforts is a foundation of use cases and requirements that can support the entire industry in the roadmap development process.

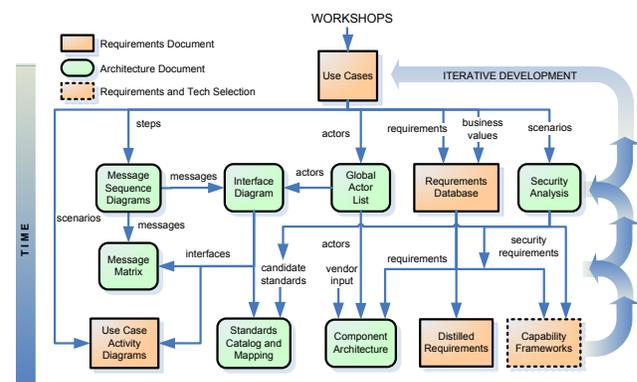


Figure 1. Illustration of Intelligrid Methodology used to develop requirements and specifications for the smart grid infrastructure.

The following sections describe the roadmap development process and also outlines for development of an information repository for sharing of information related to use cases, requirements, and smart grid technologies that can help other utilities develop and refine their roadmaps for smart grid development and deployment.

## UTILITY STRUCTURE FOR DEVELOPING A SMART GRID ROADMAP

The first step in the roadmap development process is to establish an organizational structure that can provide support for the process across all the different parts of the organization that are impacted. This requires high level executive support as well as technical resources throughout the company that are

given time to coordinate on defining the system requirements. One example of an organizational structure adopted is shown in Figure 2. With this structure, cooperation and coordination across the company helps assure the validity and completeness of the requirements developed.

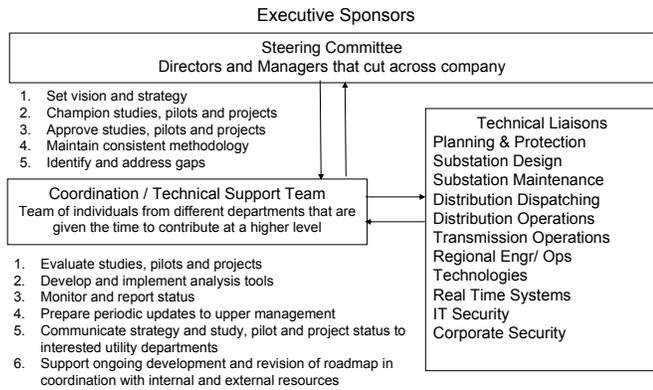


Figure 2. Example of sponsorship and coordination required to develop a smart grid roadmap.

### CHARACTERIZING THE SMART GRID APPLICATIONS (USE CASES)

The smart grid infrastructure supports applications from the transmission system to the consumer (Figure 3). This is the reason that the organization to support the roadmap development must cut across the entire organization. The next step in the process involves defining critical applications that can be used to derive the infrastructure requirements.

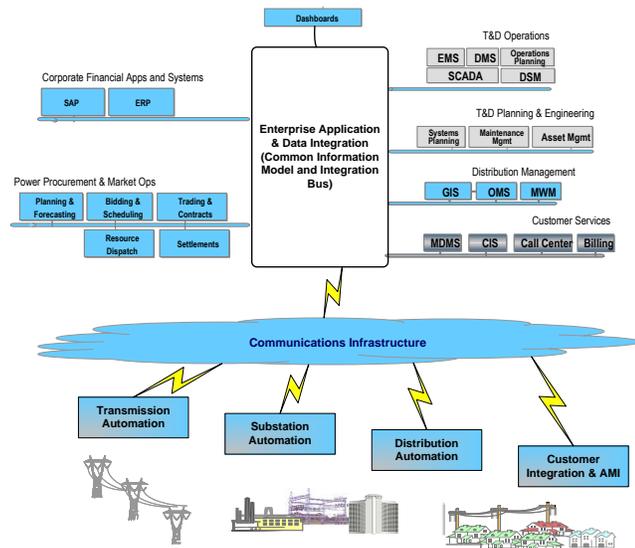


Figure 3. Implementation of Integrated Grid Communications and Information systems to support automation at different levels of the system.

Original use cases for a smart grid were developed by the Intelligrid Architecture Project. These use cases were organized into six functional domains:

- Transmission operations
- Distribution operations
- Distributed energy resources
- Customer services

- Market operations
- Centralized generation

The use cases developed in the Intelligrid program can provide a valuable starting point for individual utilities developing requirements for their own smart grid infrastructure. However, specific use cases that build on the vision, applications, and existing system architecture and processes are required to develop a utility-specific roadmap. Table 1 is an example of the internal use cases developed by one utility for their smart grid requirements development. These use cases are selected by the team based on the following criteria:

- Address the specific utility vision for a smart grid,
- Define the most architecturally significant applications in terms of requirements.
- Have a high probability of being justified on the basis of improving reliability, access to asset and customer information, improved system performance and efficiency.

TABLE I. EXAMPLE OF USE CASE SELECTION FOR SMART GRID REQUIREMENTS DEVELOPMENT

Transmission	1. Transmission Fault Location
	2. PMU Data Collection and Management
	3. System-Wide PQ Monitoring, Integration with Asset Management
	4. Asset Condition Monitoring (Advanced Sensors)
	5. Real Time State Estimation
Distribution	6. Distribution Fault Location
	7. Distribution System Management with automated reconfiguration
	8. Distribution State Estimation (performance optimization)
Customer Integration	9. Web-Based Energy Use Information for Customers
	10. Real Time Pricing Information for Customers
	11. Monitoring and Management of Distributed Resources

Each use case is documented using application descriptions, definition of actors that are required for the application, and message sequence diagrams that illustrate the information flows and decisions associated with the application. Information flow diagrams are developed to illustrate the important relationships and these diagrams can be combined for multiple use cases to illustrate the relationships across an important part of the infrastructure. Figure 4 is an example for the use cases associated with transmission operations.

### EVALUATING TECHNOLOGIES FOR THE COMMUNICATIONS AND INFORMATION INFRASTRUCTURE

A key requirement for the roadmap is an evaluation of technologies that will meet the requirements as defined from the use cases. The technology assessment can be structured using the concepts of service groups (Figure 5). The concentric rings in the figure indicate more generic, shared or common technologies toward the center, and more specialized, project-specific or application-specific technologies toward the outside.

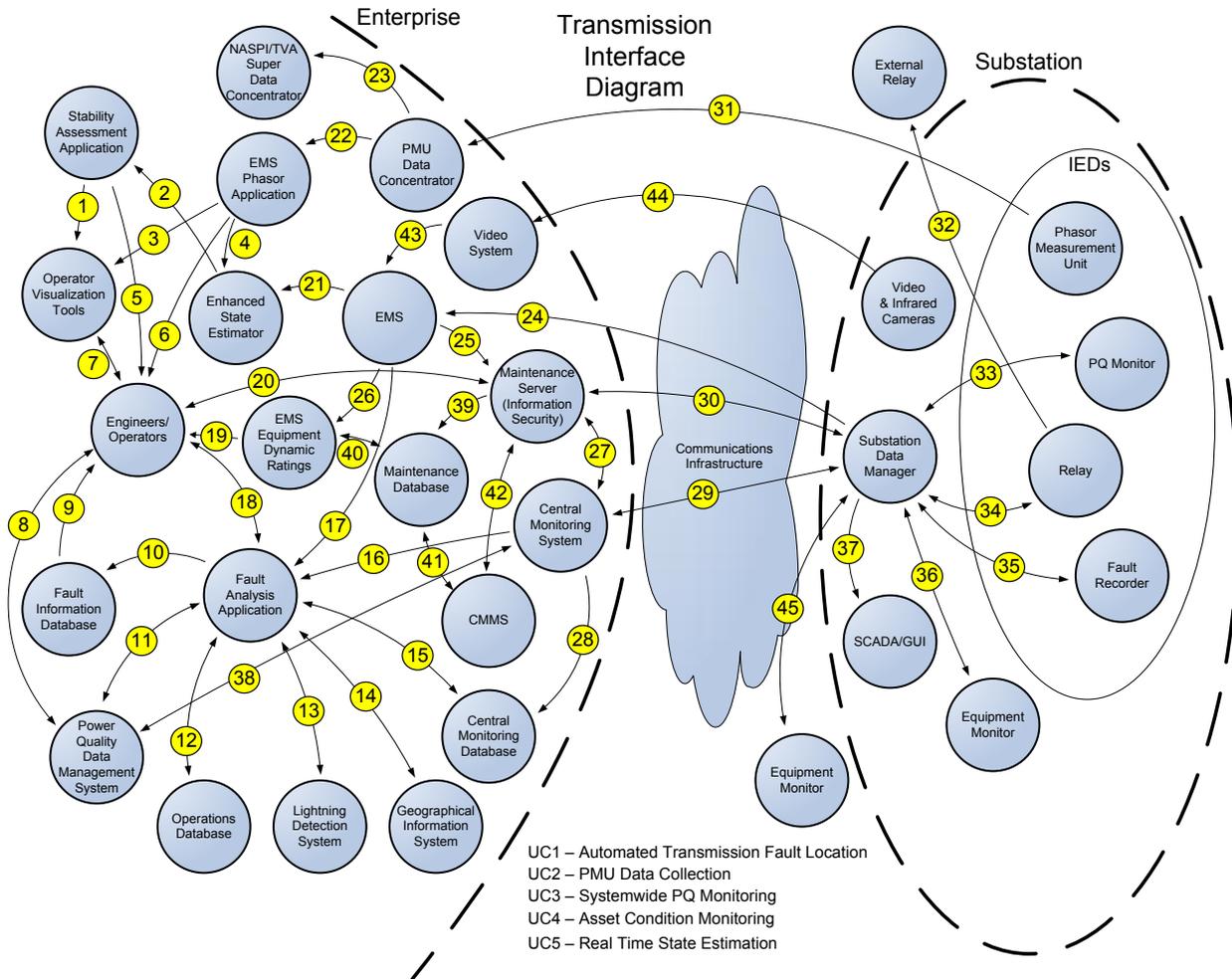


Fig. 4. Example of information flow diagram for transmission application use cases for one utility roadmap development.

When selecting technologies for the smart grid infrastructure, we start at the center and work outwards. Examples of technologies in each of these service groups that are likely to be part of the smart grid reference design are described briefly below.

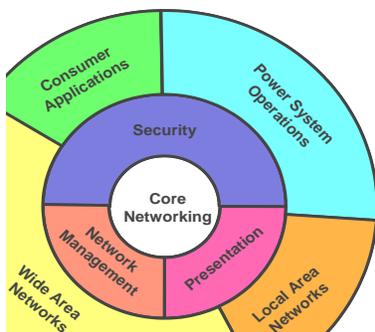


Fig. 5. Concept of service groups for evaluating technologies that are required for the smart grid..

- **Core Networking** – The Internet suite of protocols are an example of the core protocols for basic

smart grid communications. They have advantages in their low cost, widespread availability and interoperability with a variety of networks and devices including hardened substation compatible switches and other network devices that support current and future capabilities such as IEEE 1588.

- **Security** – A variety of technologies are commercially available for securing IP-based networks. Key decisions in this area relate to methods of securing wireless networks, and the choice of Transport Layer Security (TLS) or IP Security (IPsec).
- **Network Management** – Leaders in this area include Simple Network Management Protocol (SNMP) and Common Management Information Protocol (CMIP).
- **Data Structuring and Presentation** – A number of commercial computing technologies are available that address this need, such as Extensible Markup Language (XML) and HyperText Markup Language (HTML). The key issue here will be how to apply these technologies to the power industry, using specialized schemas similar to IEC

61850-6 Substation Configuration Language (SCL) and new DNP Schema.

- **Wide Area Network (WAN) Technologies** – The major competitors in this area are changing and evolving rapidly, including SONET, ATM, Frame Relay and MPLS. It is important to note that a successful smart grid reference design will allow devices to be implemented independently of WAN technologies.
- **Local Area Network (LAN) Technologies** – A good reference design should be independent of LAN technology. Different portions of the infrastructure may implement different LAN technologies. Copper and fiber Ethernet will likely be implemented in substations with potential for wireless within the substation for select applications. For communications to feeders, Multiple Access (MAS) radio, fiber, WiFi (IEEE 802.11a,b,g) and WiMax (IEEE 802.16 ) are the candidate technologies. For AMI communications PLC, BPL, Wireless, WiFi and WiMax are the candidate technologies for point to multi-point configurations. Meshed peer to peer networks also offer significant potential. For mobile workforce leased cellular (4G), WiFi and WiMax are the leading technologies.
- **Power System Operations** – The best choice in this area will likely depend on which technology a particular utility has already installed. The leading substation and Telecontrol (SCADA) protocol suites include DNP3, IEC 60870, IEC 61850, and the Common Information Model (CIM). The leading phasor measurement communications protocol is IEEE C37.118-2005. Event record formats should be in IEEE COMTRADE. Power quality record formats should utilize PQDIF (IEEE 1159.3).

## DEFINING THE COMMUNICATION AND INFORMATION ARCHITECTURE

The technologies for the smart grid will be selected as part of an informed decision making process that starts with determining the overall system architecture. Figure 6 is an example of an architecture that provides a structure for support of communications and information management down to the substation level. The substation can then be the gateway for distribution system applications. Expansion of the architecture to address advanced metering, demand response, and distributed resource integration can be accomplished in a variety of different ways and is a very important part of the roadmap development.

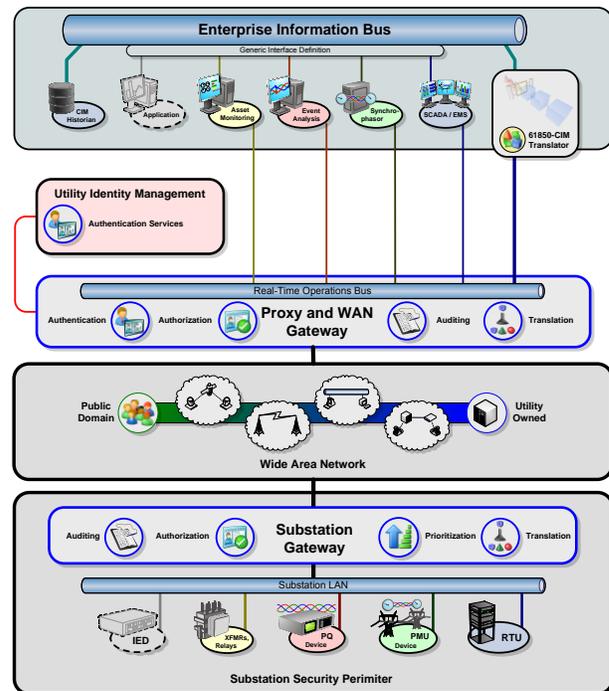


Fig. 6. Example of communication and information architecture to support applications down to the substation level.

## MIGRATION PATH FOR THE SMART GRID IMPLEMENTATION

The final step of the roadmap is defining the migration strategy for actually implementing the recommended technologies and infrastructure to support smart grid applications. This process depends on legacy systems, cost/benefit assessments for the particular applications, and the infrastructure requirements to support the applications. A general approach is to define projects that will facilitate ongoing technology assessments within the guidelines of the overall smart grid reference design. The outputs of these projects will help refine the benefit propositions for the applications and provide better estimates of the costs and requirements for more widespread deployment.

A general flow of implementation that is likely for many systems is shown in Figure 7. It illustrates building out the infrastructure to successively lower levels of the system. However it is important to consider the requirements for applications all the way to the consumer (advanced metering, distributed resource integration, demand response) because these applications have implications for the entire infrastructure and there may be possibilities for common use of the infrastructure for a variety of different applications.

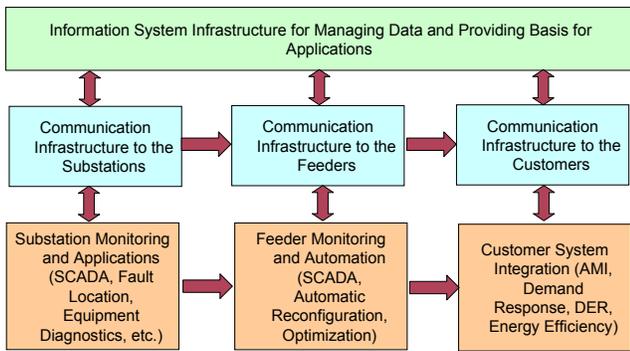


Fig. 7. Implementation of Integrated Grid Communications and Information systems to support automation at different levels of the system.

## SUMMARY AND CONCLUSIONS

Many utilities are developing a vision for the development of the future smart grid. The vision involves an integrated communications and information system infrastructure that supports a wide variety of intelligent applications from asset management to power system operations. With the tremendous investment involved in accomplishing this vision, it is critical that a structured approach for defining the infrastructure requirements and the technologies is used. The Intelligrid Methodology provides a foundation for this process and the combined efforts of many utilities to derive requirements from a common base of use cases can help assure that the technologies being deployed are based on industry standards that will have long term support. With a set of common requirements and technologies, each utility can develop implementation plans based on specific priorities, existing systems, and cost/benefit assessments

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# An Intelligent Demand Side- Control of Distributed Generation

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**Keywords:** agents, distributed energy, demand management

## Abstract

Strong growth in Australia's electricity demand is resulting in increasing numbers of constrained network distribution areas. While the traditional solution has been to build additional generation, transmission and distribution infrastructure, there is increasing interest in solving these problems from the demand side. Such solutions include the use of distributed renewable energy systems, cogeneration and load (demand) response schemes.

This paper introduces CSIRO's work on the demand side of the electricity grid, coordinating large numbers of small-scale generation systems.

## 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.

Recently, there has been a significant amount of media attention focussing on what is a perceived electricity supply problem in parts of Australia, and indeed many other parts of the world - in short, with aging network infrastructure, a growing peak electricity demand from loads such as air-conditioners, and ever increasing base-load energy consumption, electricity generation and distribution systems are being seen as unable to cope with the demand placed on them. Whilst the traditional solution to such issues has been to build more supply infrastructure, there is an increasing interest in solving these problems from the demand side. For example, consider the peak-load growth issue - addressing this through supply-side augmentation is an incredibly inefficient approach - whilst peak loads can be double the average base load on a network, they often occur for only a few days per year.

In addition to supply and distribution issues, countries like Australia trade electricity in a relatively volatile energy market, where the price for a unit of electricity can vary from \$10 per megawatt-hour, to \$10 000 per megawatt-hour, in the space of a few minutes. Such volatility represents a significant risk to electricity retailers, who spend significant amounts of money on financial instruments to manage such risk.

In using demand-side solutions to address these problems, we expect the organisations that will benefit most from such solutions (electricity distributors and retailers) to pass such financial benefits on to the end-user. Such concepts are relatively immature in Australia, but are enjoying growing acceptance throughout the world. For example, energy policy in the United States now states that demand-side measures *must* be actively encouraged [1]. Such policy has been a catalyst for many new businesses in the US market - from energy services organisations who will manage DE plant for a business, to manufacturers of new, clean, embedded generation technology.

In Europe, the International Energy Agency has several demand-side programmes ongoing [2], and embedded generation solutions are enjoying particular growth because of the efficiency improvements possible in cold climates using combined heat and power technologies. Closer to home, two recent Australian programmes have demonstrated the real-world benefits of DE in Australia:

In Western Australia, Western Power's "Peak Demand Saver" programme used demand-side measures to significantly reduce summer peak demand. Western Power invited customers to join a programme where they would be called a number of hours before a peak demand event, and invited to either shed load or activate backup generation systems. In return for their response, customers were paid to be available for call-up, and enjoyed significant financial rewards if they did actually shed load or activate generators. With a mix of generation from backup systems and load shed from industrial customers, Western Power were able to obtain close to 40 MW of response, with at least 1 hour of notice given to customers before a response was required.

The Australian National Electricity Market management authority, NEMMCO had 375MW of standby capacity across the entire east coast of Australia during the summer of 2005/2006. Participants in this programme were also paid availability, pre-activation and usage components, and asked to provide reserve response ranging from 1 hour per day to 15 hours per day, with varying limits on the total hours of usage. Participants in the NEMMCO programme included individual (relatively large) industrial clients (the smallest response was 15MW), as well as an aggregation business, who effectively sub-contracted much smaller clients to provide their own response, which was then combined into an aggregate of up to 125MW for presentation to NEMMCO.

For the moment, if we just consider the embedded generation aspect of DE, a recent study by the New South Wales Department of Energy, Utilities and Sustainability (DEUS) found over 332 MW of standby generation capability in the Sydney CBD area [3]. Such generation can play a significant part in addressing the electricity industry issues discussed above- embedded generation can be used to supply local demand, easing the demand on constrained distribution networks, and electricity retailers can use embedded generation to gain some *firmness* in their system loads, thereby reducing their exposure to volatile market prices. Whilst standby generation is usually based on fossil fuel sources, these can be relatively efficient if they are based on co- or tri- generation techniques. If we consider the growing amount of renewable generation sources in modern electricity networks, the total generation capacity here is even greater.

Considering another case, in a 2004-2005 study of the customers connected to the Revesby substation [4-5] near Bankstown, Sydney, the local utility EnergyAustralia identified a local customer who owned a 3.2MW emergency power supply that could be used for demand management. They estimated that a fully costed first year of operation, using the previously standalone generators in a grid connected configuration would cost (2005) \$347,000. With essentially an on-going availability of the generator for demand management (but a local override available for customer emergency use), EnergyAustralia estimated an *annual customer income* of \$90,000. Standby generator warranties are typically available for 5 and 10 years [6], implying an average expected lifetime exceeding these durations. The identified emergency power supply hence gained an expected net present value for the consumer of over \$420,000. EnergyAustralia was to assume \$230,000 of the up front costs of the emergency power supply upgrade by using future income from other customers corresponding to the generators in operation to pay it off. This results in a potential of up to \$650,000 net present worth for the customer.

Whilst cases such as the Revesby Substation and NEMMCO's programmes have demonstrated the business case of DE techniques in Australia, and that the general concept is enjoying growing acceptance in the marketplace, a number of technical issues remain before backup generators can play a significant part in Australia's electricity network. These are outlined in the following section.

## 2. IMPROVED CONTROL OF LOADS AND GENERATORS

One of the fundamental challenges around introducing large amounts of distributed generation into an electricity network is how to control large sets of dispersed, often technically varying, generation. Before describing our most recent techniques 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 control system that broadcasts a "turn on" command to large numbers of generators. Without consideration of the operating parameters of those generators- for example, whether sufficient fuel is available for the generator to provide the desired quantity of energy, the system will never reach the desired reliability. 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 fuel availability, cost of supply, and so on.

Whilst 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 device 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 [7]. 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 [7], [8]. Given these limitations, the research community is trending towards new approaches to the control of electricity networks, based on distributed, *learning* systems.

### 3. AGGREGATION OF DISTRIBUTED GENERATION

The key limitation that prevents distributed energy sources such as backup generators, solar and wind actively contributing to the robustness and reliability of the electricity network is their intermittency- the energy available from a particular source at any one time can vary quite significantly. This intermittency means that it is quite difficult to make a distributed generation (particularly renewable) energy system dispatchable, which is needed for it to participate in time varying energy markets such as the NEM.

If we consider one particular type of distributed generation, small-scale solar photovoltaic (PV) systems, these can be seen to be even more challenged- not only are they time varying sources of energy, but the net quantity of energy actually available from such systems is so small that it is generally not of any interest to electricity market participants.

The aim of our generation control work is to combine a large number of geographically disperse and technically diverse small scale distributed generators in a way that will allow them to present to the electricity market as a single reliable dispatchable entity. The output of distributed generation technologies is often dependant on local environmental conditions, so it is only through advanced forecasting, communications and control that these resources can collectively provide a firm, dispatchable generation capacity to a participant on the electricity market.

#### 3.1. The Basic Concept

Rather than one relatively expensive, centralised generation plant, our work is based on aggregating the electrical contribution possible from a large number of smaller energy generation and storage systems. This may comprise roof-mounted solar photovoltaic panels, and associated grid-connected battery systems, or larger “dark-green” fossil-fuel powered efficient generators.

These individual systems are then aggregated together, to form one coordinated response, of benefit to the wider electricity network. This source of generation is expected to

have a number of advantages over the more common centralised plant traditionally used:

- It is based on highly efficient fossil fuel generation sources, or renewable energy technology, so has reduced emissions compared to many types of centralized generation.
- Being distributed, there is no central point of failure- fundamentally, the system is much more reliable and fault tolerant than one single generating plant.
- The concept increases the functionality achievable from multiple dispersed generation systems- so rather than requiring the construction of entirely new plant, we are able to take advantage of existing generation systems.
- The system operates at a very low level of the electricity distribution system, so can be used to meet highly localised system issues- transmission failures in one particular street for example.

#### 3.2. Implementing the Virtual Power Station

We’ve recently completed a demonstration of our distributed generation control system. The deployment consists of eight sites, two of which include both photovoltaics (around 1kW peak each) and energy storage (in the form of deep cycle lead acid batteries) which is controlled with a grid connected interactive charger/inverter. The remaining six sites have photovoltaics but no energy storage. A typical hardware installation for a photovoltaic only site is shown in Fig. 1.

Our control system links the dispersed renewable energy generator and storage sites through a web-based communication network. Each discrete generator and storage system is fitted with a small, relatively cheap embedded computing platform which interfaces to the inverter to obtain PV generation output data and to provide battery charge/discharge and grid feed instructions. Each of the sites is linked back to our central controller with an Internet Protocol based communications system. The central controller determines the individual inverter setpoints and broadcasts these control decisions out to the sites.

The central controller is implemented on a web server. The server has a web front end that allows users to easily view both real-time and historic system performance information. See Fig. 2 for a screenshot of this system.



**Fig. 1:** Typical hardware installation for a photovoltaic only site – consisting of 3kW peak PV, inverter and embedded controller with wi-fi communications.



**Fig. 2:** Page from the generator control website that provides a quick overview of the status of sites.

#### 4. OPERATIONAL EXPERIENCE

Having constructed the core system, our technical experiments with our generation control system have just started, and we look forward to reporting on these soon. In addition to the obvious technical aspects of the system, there have been some interesting social and reliability aspects to the project. The key aim of this work is to improve the value of distributed generation in the electricity network. The management interface website allows individuals to easily see their contribution to the system - the opportunity to be part of this ‘generation community’ has already gained

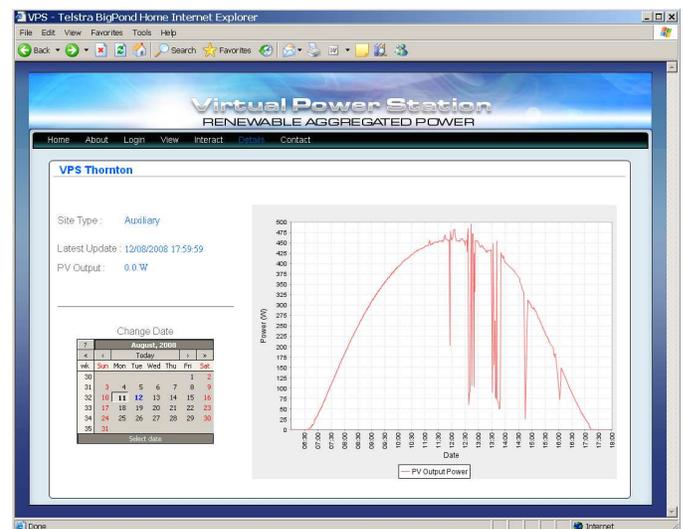
significant interest with individuals, community organisations and eco-developers. There is an additional reliability benefit here in that the web-based monitoring of the generation systems allows system problems to be quickly identified. In our experience with 120kW of PV installed at the CSIRO Energy Centre, at times we have seen up to 20% of this capacity not functional. Energy Australia experienced a similar situation with their investigation of the Kogarah Town Square 160kW PV system, where between 20-39% of inverters were not-functional at different times throughout the trial [9]. The ability to identify these problems quickly is crucial to having renewables reach their full potential. Fig. 3 shows a typical web page for an individual (PV only) generator.

#### 5. CONCLUSION

Distributed generation systems are being rolled out in electricity networks across the world as a way of reducing greenhouse gas emissions, dealing with peak loads and improving network reliability. Whilst it is certainly encouraging to see these systems and the benefits they bring, the control of such systems to realise global benefits remains a considerable challenge.

This paper introduces our work on the optimal control of demand side resources such as distributed generation plant. Our control techniques are based around aggregating large numbers of dispersed generation sites so that they appear to the wider electricity system as one large, dispatchable and reliable generation plant.

Having demonstrated the basic infrastructure to achieve such a goal, our technical experiments with this system have just started, and we look forward to reporting on these in greater detail soon.



**Fig. 3:** Web interface for a typical PV generator in the system.

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# An Approach for Open and Interoperable AMI Integration Solution

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**Key Words:** Advanced Metering Infrastructure (AMI), IEC CIM, IEC 61968-9, MultiSpeak, Service-Oriented Architecture (SOA), Integration Architecture, Technical Interoperability, Semantic Interoperability, Enterprise Information Management (EIM).

## **Abstract**

Utilities across North America are investing tens of millions of dollars in implementing the Advanced Metering Infrastructure (AMI) and the Smart Grid technology and solutions. Key concerns remain about the stability and maturity of solutions being offered in the market today. As utilities solidify their visions on Smart Grid and as technologies advance to address the market needs, AMI solutions will continue to evolve and consolidate at a rapid pace. As a result, utilities need to be confident about moving forward with Smart Grid investments and not be stranded by costly and proprietary technologies as they choose to implement the core of an AMI solution.

This paper addresses the need for an open and interoperable AMI integration solution that is based on industry best practice integration architecture frameworks and standards. Such a solution would enable a utility to implement AMI incrementally and in alignment with business priorities and available industry solutions, within an interoperable framework. While standards such as IEC 61968-9 and MultiSpeak provide necessary components for open AMI

integration solution, not all the pieces are available from a single standard. A detailed approach has been developed to address both the technical and semantic interoperability needs of an open AMI integration solution. This approach includes key architectural designs such as integration requirements analysis for service identification, service patterns, semantic models, integration schema design patterns, and mapping to standards for compliance and openness.

Authors will share Consumers Energy's endeavor to develop and implement such an approach, with the goal of collaborating with key vendors and utilities to drive de facto implementation of desired standards. Ultimately, this approach will enable utilities to reduce both risk of implementation and cost of ownership, and increase their flexibility in building out the Smart Grid capability as technologies evolve.

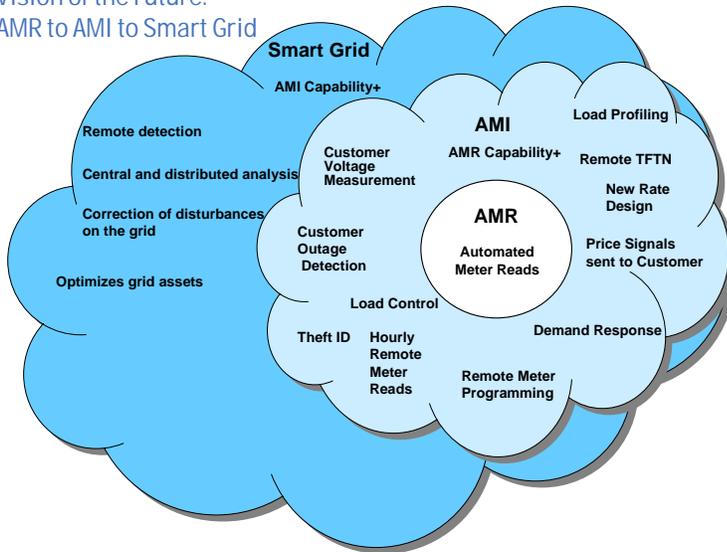
## 1. MARKET NEEDS

### 1.1. Utility Business Drivers

Consumers Energy has several high-level goals that drive the enterprise, and the AMI investment supports these goals in a number of ways. Consumers Energy believes that an AMI system provides the foundation for the Smart Grid; so while the Smart Grid is not being built yet, it is anticipated that the communication infrastructure that is deployed to support AMI will be leveraged as Smart Grid technologies are deployed, see Figure 1. The high-level business strategies are:

- Leverage business environment knowledge
- Ensure efficient and effective operations
- Develop a safe and skilled work force
- Deliver what customers and regulators value
- Manage risk and capitalize on change
- Consistently achieve financial results

Vision of the Future:  
AMR to AMI to Smart Grid



**Figure 1: AMI, A Foundation for Smart Grid**

#### **Leverage business environment knowledge**

Any significant technological advance has both competence-enhancing and competence-changing components. AMI includes competence-changing aspects such as the knowledge associated with manually reading a meter. Competence-enhancing components include leveraging the meter and grid performance expertise of engineers, the ability of the company to analyze where outages are occurring, and the ability of the company to leverage its investment in updated information systems to enable new business processes.

#### **Ensure efficient and effective operations**

The AMI system will facilitate efficient and effective operations in several ways: eliminating the operations and maintenance (O&M) expenses related to meter reading by automating this function; reducing the number of visits to a premise associated with a meter by automating the turn-on/turn-off function; reducing theft by indicating when someone is tampering with a meter; and automatically reporting consumption for all meters connected to the network, thereby reducing the number of “lost” meters. Smart meters will allow the capture of distribution information that may enable analysis to help prevent distribution failures before they occur. The AMI system will also facilitate quick localization where outages have occurred.

#### **Develop a safe and skilled work force**

AMI will eliminate the need for Consumers Energy to manually read meters with meter readers. The company does not know what the outcome will be for the current meter readers as it is dependent on what internal job opportunities are available at that time. The AMI system deployment will reduce or eliminate the “foot-miles” traveled, reducing the company’s exposure to safety issues related to meter reading, such as slip, trips and falls and dogs bites. The ability to do a remote disconnect of an electric meter will also eliminate the need for an employee to visit a potentially hostile premise.

#### **Deliver what customers and regulators value**

Michigan’s 21st Century Energy Plan and the Energy Policy Act of 2005 have called for utilities to enable greater energy efficiency and demand response systems. AMI is an enabler of demand response by communicating time-of-use (TOU) rates to the meter, facilitating the ability of consumers to make informed decisions about their usage. TOU will also allow easy customization service offerings for all classes of customers. Reducing the turnaround time associated with turn-on/turn-off by performing this task remotely, arming the consumers with information, along with the ability of the utility to improve reliability and responding more quickly to outages, will increase customer satisfaction.

#### **Manage risk and capitalize on change**

AMI incorporates several leading-edge technologies. Utilities must be careful when making technology choices, especially considering a smart meter may be deployed for at least 15 years. Consumers Energy has been working with industry thought leaders and leading vendors, and

“borrowing the brains” of other utilities that are in similar places within the AMI implementation life cycle to manage the risk with its AMI deployment. Consumers Energy is being very thoughtful in the assessment phase to carefully consider each technology component. Because AMI will fundamentally change how Consumers Energy does its business, consideration is being given on how to best capitalize on this change and best manage the relationship with the company’s customers and regulators.

**Consistently achieve financial results**

The AMI investment presents opportunities for Consumers Energy to better achieve its financial goals. The idea is that an investment in AMI uses capital to reduce O&M expenses. Some of these O&M reductions were noted previously. The capital investment used to fund AMI is expected to be recovered through a rate case. Rate recovery will contribute to the utility’s ability to realize its authorized return on equity.

**1.2. Information Technology Trends**

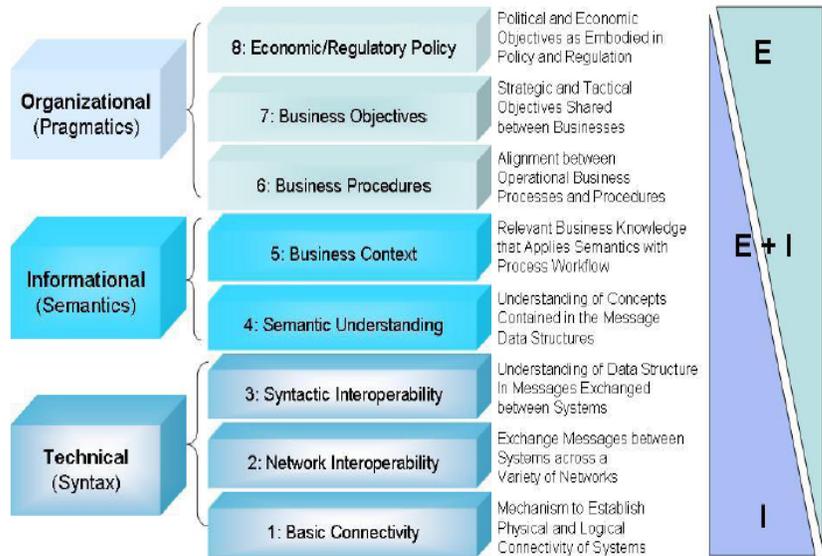
While the utility industry is going through tremendous changes due to increasing demand and higher energy prices, the information technology industry continues to mature with regard to technologies for systems integration and information management. Most notable are the technology solutions that deliver Service-Oriented Architecture (SOA) and Enterprise Information Management (EIM) capabilities, allowing enterprises to improve system interoperability and manage and leverage information more consistently and intelligently. The evolution of web technologies from yesterday’s hyperlinks to tomorrow’s Semantic Web has brought us semantic integration technologies that are aimed for semantic interoperability. The technologies that deliver SOA, EIM and Semantic Integration are advancing and maturing rapidly, and are ready for the utility AMI and Smart Grid initiatives to take advantage of.

**1.3. GridWise Interoperability Framework**

The GridWise Architecture Council recognized the importance and need for developing and promoting an interoperability framework that will facilitate the development of open and interoperable AMI and Smart Grid solutions. As the result, it published an Interoperability Context-Setting Framework, see Figure 2.

This framework calls for addressing interoperability at three levels — Technical, Informational, and Organizational — as well as cross-cutting issues such as “Share of Meaning of Content,” etc. Such a comprehensive framework is both

necessary and useful as vendors and utilities work together to move forward with the vision of the intelligent utility of future.



**Figure 2: GridWise Interoperability Framework**

The approach developed as part of the Consumers Energy AMI program addresses the Informational level of the interoperability framework and how the consistent semantics can be used to drive the Syntactic Interoperability using Service-Oriented Architecture technologies.

**2. AN OPEN AND INTEROPERABLE AMI INTEGRATION SOLUTION**

**2.1. Main Objectives**

Before considering the objective of an open, interoperable integration standard, an environment needed to exist that fostered this desired end state. Several factors contributed to this environment. Some of the impetus for the move to AMI was the Energy Policy Act of 2005 and, in Michigan, the 21st Century Energy Plan that outlined the need to reduce peak energy demand requirements. These actions created a favorable legislative environment that encouraged the type of capital investment that would be required to develop an AMI system. A favorable technology environment at the utility needed to exist as well. As part of significant investment in its business systems, Consumers Energy migrated numerous legacy systems into a single comprehensive enterprise application. The result of this migration was the removal of many point-to-point interfaces

that would have made integration to an AMI system more complicated and costly. Finally, the metering technology that was available to support AMI systems matured to the point that AMI systems were now practical. These three forces created the perfect storm of events that led to a decision to invest in an AMI system.

Once a decision had been made to make the AMI investment, thoughts could then be turned to the nature of that investment. An examination of the offerings in the AMI market revealed a mix of communication technologies, including some vendors with proprietary interfaces or vendors that had replicated back-office systems in their metering databases. Having recently migrated legacy systems into a comprehensive enterprise application, there was no desire to create another application silo. One of the lessons learned from that legacy migration was that open, interoperable interfaces reduce the implementation costs and facilitate an environment that is more agile compared to point-to-point or proprietary systems.

## 2.2. The Approach Overview

### Introduction

Utilities have realized the need to invest in communication networks infrastructure and IT technology infrastructure for integration and data management. Without a shared understanding of how different systems' data is structured and expressed, however, the technology infrastructure will crumble to its knees due to massive amounts of point-to-point data translations. The only way to scale the integration platforms to meet the future demand for process integration and business intelligence needs is to ensure that the data flowing through the various integration platforms have the same business semantics. They make the same sense for all systems and people that consume them without duplicating effort for translation and interpretation; as such effort at individual levels will inevitably increase cost and opportunity for errors.

To help utilities understand where they are and where they want to go, a simple Intelligent Utility Information Management Maturity Model, see Figure 3, is developed to guide the decision-making process as to where to invest utilities' valued information technology and operational technology dollars.

Level One: Ability to integrate and allow access of data from applications, but still confined within business units and domains. No enterprise view and consistency.

- Point-to-point integration
- Application-driven data marts and business intelligence
- Duplicate and overlapping data, information, infrastructure, etc.

Level Two: Ability to manage both data and information (meaning of data) with common governance and infrastructure for consistent, accurate, and on-demand needs of information to drive improved operations.

- Enterprise strategy and governance for managing data as assets
- Business semantic and metadata management
- Consistent integration and information management platforms
- Ability to obtain data and information when it is needed with trust

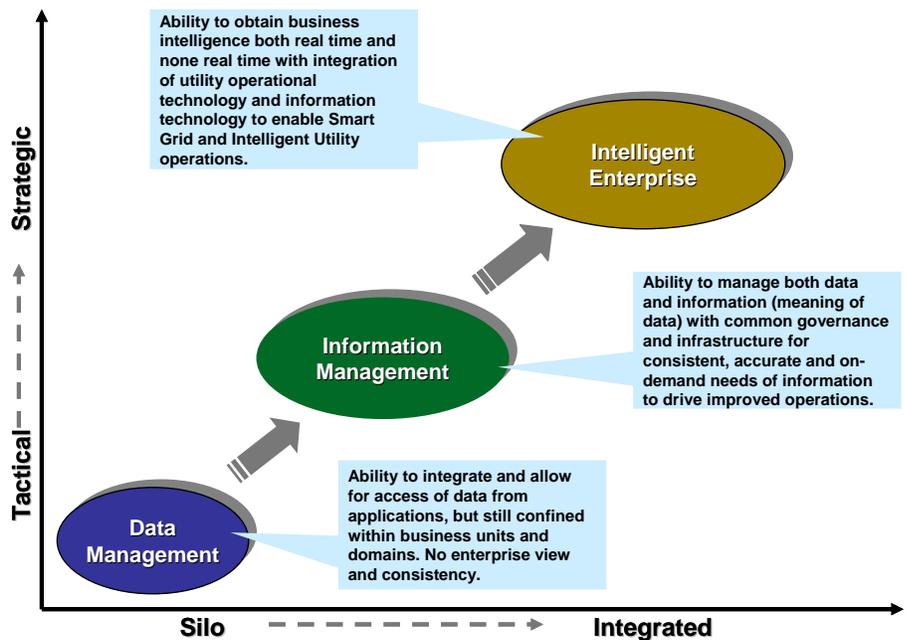


Figure 3: Intelligent Utility EIM Maturity Model

Level Three: Ability to obtain business intelligence in both real-time and none real-time with integration of utility operational technology and information technology to enable Smart Grid and Intelligent Utility operations.

- Ability to derive intelligence from many sources of data and information to drive and optimize operations
- Ability to adapt to new business requirements and operational needs with different data/information

While some utilities are still trying to get from Level One to Level Two, others are poised to take on the challenges of establishing the strong foundation of EIM and leveraging their SOA investments to move toward an Intelligent Enterprise, see Reference 1. SOA and EIM have been adopted by Consumers Energy’s AMI program to achieve an interoperable AMI solution that combines industry standards and common practices. As one of the best practices in enterprise integration, SOA provides consistent, reusable, scalable and extensible business integration solutions. EIM provides necessary governance, methodology and technologies to develop common informational models (i.e., integration canonical models used to develop services that achieve both technical and semantic interoperability). Another key consideration for developing the approach to deliver an open and interoperable AMI integration solution is the GridWise Interoperability Context-Setting Framework. The project focuses on addressing the Informational level of the interoperability framework and determining how the consistent semantics can be used to drive the syntactic interoperability using Service-Oriented Architecture technologies.

The approach to developing an open and interoperable AMI solution development includes the following key components:

- A structured approach for analysis and design using model-driven methodology for consistent business semantics and leveraging industry standards such as IEC CIM and MultiSpeak, which drive toward semantic interoperability.
- A set of service-oriented integration patterns and web services standards to drive technical interoperability.

**Model-Driven Services Analysis and Design**

There are two main steps involved in Consumers Energy’s AMI solution development: high-level analysis and detail level analysis and design, see Figure 4.

In high-level analysis, a top-down approach is followed with the major steps listed below and illustrated in the diagram:

- Develop To-Be business process models for AMI
- Review To-Be business processes and conduct gap analysis by utilizing industry standards
- Identify integration requirements (services and information objects) in a context of business process
- Normalize services and information objects for detail design

Business processes provide a collection of activities across multiple systems and applications. They are essential for identifying integration requirements (services and information objects) from business perspective. Data flows captured in a business process often indicate integration lines.

Multiple industry standards such as IEC CIM and MultiSpeak are used as a basis for developing interoperable AMI solutions. Logical mapping from business processes to the standards is conducted to align Consumers Energy’s business needs with existing industry common practices.

The outcomes of the High-Level Analysis provide the Business Context (see the GridWise Interoperability Framework) within which integration services function. This is critical for an open and interoperable AMI solution to be adopted by multiple utilities and vendors.

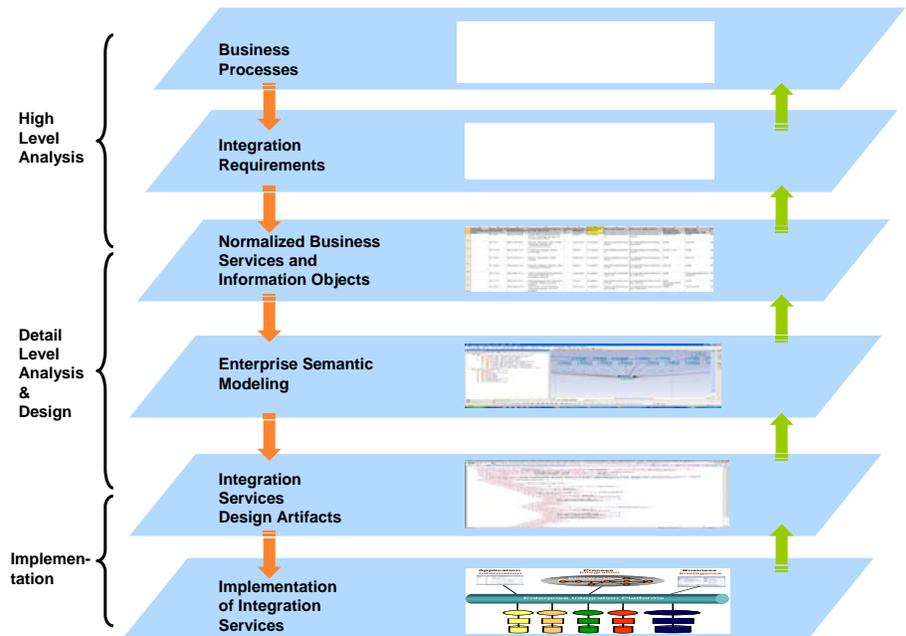


Figure 4: Model-Driven Services Analysis and Design

Based on data flows between systems and applications, information objects can be identified with a collection of entities and properties unique to a business context. With multiple business processes, it is possible that an information object is identified in another business process or overlapped with other information objects. Therefore, it is critical to have a normalization process that defines objects at a certain level of granularity based on business needs.

The normalization process can help define a relatively accurate scope of the detail design phase with a list of common services and information objects that need to be constructed.

In the detail design phase, a combination of top-down and bottom-up approaches is employed. The steps involved are as follows:

- Review identified data requirements (services and information objects)
- Develop Consumers Energy Enterprise Semantic Model (ESM) for AMI with business context for each integration scenarios.
- Deliverable in XML schemas and Web Service Definition Languages (WSDLs)

The outcomes of the Detail Level Analysis provide the Semantic Understanding (see the GridWise Interoperability Framework) upon which all integration services design artifacts will be based. This is also critical for an open and interoperable AMI solution to be adopted by multiple utilities and vendors.

The goal of the detail design is to provide sustainable implementation artifacts in terms of performance, reliability, reusability, interoperability and so on. For this reason, the identified services and information objects from high-level gap analysis need to be examined carefully to avoid unnecessary rework in the future as much as possible. Implementation artifacts are delivered in the form of XML schema (XSD) for information objects and WSDL for endpoint service definition.

Model-driven methodology is adopted for the detail design process. Information objects are modeled in UML. The objects modeled in UML come from the logical information objects identified from high-level analysis (top-down), data requirements from each systems/applications and industry standards (bottom-up). After a data model is constructed, generating design artifacts using Xtensible Solutions' MD3i Framework is an automated process.

The inputs to the Consumers Energy ESM are the IEC CIM and MultiSpeak standards, which will ensure that integration services and payload designed are going to be compatible with the standards and can be promoted back to the standard bodies for wide adoption. This also ensures the openness of the solution from business process to services identified and designed.

The success of the AMI solution development largely depends on proper analysis, design, integration and testing. The cycle of the high-level analysis and detail design approach is not just one-way traffic. There can be many project life cycle iterations to get a sustainable AMI solution and achieve the best return on investment (ROI) for Consumers Energy.

### ***Service-Oriented Integration Patterns***

Strategic initiatives, such as the AMI program, are moving Consumers Energy in a direction toward adopting Service Oriented Architecture in the enterprise. Consumers Energy wants to ensure that it maximizes its ROI by using this integration philosophy wisely.

Technologies, requirements and priorities impose constraints on the system integration delivery process. Quick solutions are often developed to address these problems, resulting in point-to-point interfaces and duplication of data and business logic, which create a lack of consistency across the enterprise. This integration becomes costly to maintain and difficult to grow with the business. Part of Consumers Energy's SOA strategy includes leveraging service design patterns to ensure that service design principles are applied consistently across the enterprise, minimizing the need for quick solutions during the system integration delivery process.

The service design patterns created for the AMI program provide a documented solution in a generic template to ensure consistency in service design, compliance to industry standards, and technological independence. The service design patterns incorporate industry standards, such as WS-I and IEC TC57 WG14 verbs, and provide a consistent environment to discover and consume services across the enterprise by enforcing common service semantics. As a result, the AMI program adhering to the service design patterns will enable the reuse of decoupled services by other enterprise projects.

In Summary, the service design patterns collections consist of:

- Message Exchange Patterns
- Service and Operation Patterns
- Service Interaction Patterns

Below is an example of three patterns from each of the Service Design Patterns. The integration scenario is between two applications, where application A sends work order data to application B via a service broker.

The Operation Naming Patterns (IEC 61989 verbs) below are used in these scenarios:

- **Created** -- operation: used in Send, Receive, Reply services.
- **Changed** -- operation: used in Send, Receive, Reply services.
- **Closed** -- operation: used in Send, Receive, Reply services.
- **Canceled** -- operation: used in Send, Receive, Reply services.
- **Deleted** -- operation: used in Send, Receive, Reply services.

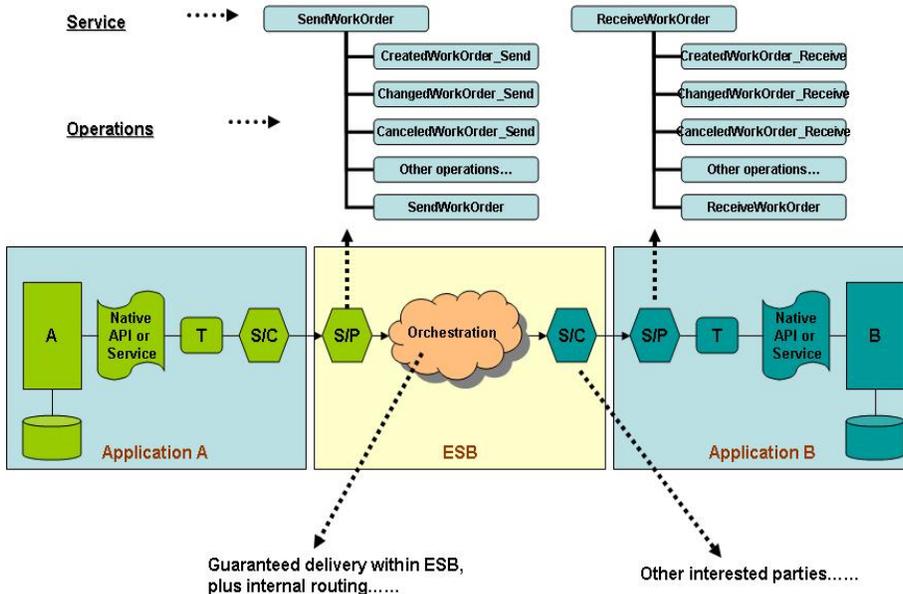


Figure 5: Send-Receive Service Interaction Pattern

Figure 5 shows Application A sends work order data through a “Send” service at the integration layer, acting as a service broker. Application B provides a “Receive” service to receive the work order data. This is an indirect interaction process, as Application A does not send its data directly to B, but through the Enterprise Service Bus (ESB). It is an asynchronous process because multiple invocation threads are involved.

The Message Exchange Pattern used in this scenario is:

- A two-way pattern is a synchronous process that typically involves two messages, one for request and one for response.

The Service Naming Patterns below are used in these scenarios:

- **Send** - to provide (send) information (information object) for public (enterprise) consumption. To be invoked by the system of record for the business object and only when the state of the business objects has changed.
- **Receive** – to consume (receive) information (information object) from an external source.

The Service Interaction Pattern below is used in this scenario:

- Send-Receive Services Interaction Pattern (Indirect & Asynchronous).

### 2.3. Benefits

This approach brings benefits to the industry for utilities, vendors and customers. For utilities, having vendors support a common set of services on a common information model reduces the cost of integrating vendor offerings into the IT and OT landscape at the utility. This also drives down the base price for utilities if vendors support standard services and information models. This is because if the services and information exchanged are the same, then vendors have to differentiate themselves on price, product performance, and execution within the market.

There are opportunities for vendors who perform well. Those who adopt common services and information models will find a welcome market. Vendors that have attempted to tie customers to proprietary products and interfaces will increasingly find this approach a difficult sell. Vendors that take the proprietary approach will have to show that their products are demonstrably better than products based on open standards and will need to justify what will likely be a higher total cost of ownership.

All AMI systems promise to arm customers with more information, allowing them to reduce their usage in thoughtful ways and reduce their direct costs by shifting their use to off-peak hours. However, the huge amounts of investments for technologies and systems required to enable such capabilities require the entire industry to drive toward

more open and interoperable solutions to reduce the risks of implementation and total cost of ownership. Although there continually will be market and regulatory pressures to move toward Smart Grid and Intelligent utilities, the market will not bear costly and proprietary solutions.

### 3. CHALLENGES

While the goals and benefits of open and interoperable AMI integration solution are clear, challenges remain that prevent making the solution a reality for the market as a whole. Chief challenges are listed as follows:

- **Market positioning:** As demand for AMI and Smart Grid solution increases rapidly, competition is heating up in the market. Inevitably, there will be parties who want to “lock” the market into their proprietary technologies, while others believe that open and interoperable solution creates a win-win situation. The rapid evolution of the technologies in this space requires a very prudent approach for adoption and implementation. While it may seem less costly to buy into the market hype and go with a “turn-key” solution, the risk of being “stuck” with unproven and proprietary technologies remains extremely high in today’s market condition.
- **Utilities and vendors community cooperation:** Achieving an open and interoperable solution for the market requires tremendous support and cooperation from the utilities and vendors community. While OpenAMI, OpenHAN, and AMI-ENT, etc. under UCA OpenSG are making significant progresses toward knowledge sharing and creating open specifications for AMI, much still needs to be done to reach de facto implementation standards for the market as a whole.
- **Industry standards evolution and harmonization:** Significant progress has been made within IEC TC57, Multispeak and other organizations to provide standards that will be supported by vendors, yet the internal processes to individual standards bodies and inter-standards competition make their adoption by utilities and vendors more complicated. It was encouraging to see IEC TC57 WG14 and MultiSpeak agree to collaborate and move both standards in the same direction. The user community needs to work together to drive these standards into something that is both implementable and maintainable.

### Reference

1. “Utility Enterprise Information Management Strategies”, Parekh, Zhou, McNair, Robinson; Grid-Interop 2007.

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Mr. Gray is an enterprise architect with Consumers Energy, a combination electric and gas utility serving more than 6.5 million customers in Michigan’s Lower Peninsula. Mr. Gray has over 25 years of IT experience in a variety of roles, and now as an enterprise architect is leading the application integration effort for Consumers Energy’s AMI program. Mr. Gray participates in and has contributed to the Open HAN and AMI–Enterprise working groups.

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#### Shawn Hu

Mr. Hu is a Solution Architect with Xtensible Solutions. His expertise includes AMI integration, utilizing SOA Web service technology, enterprise information management and detail XSD/WSDL designs. He has worked on a variety of system integration projects that focused on interface design and data flow. He holds a Ph.D. from University of Western Ontario in Canada.

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Mr. Zhou is CTO of Xtensible Solutions, which provides enterprise information management and integration solution and services to the energy and utility industry. With about 20 years of industry experience, and having provided 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 to enable and improve business and systems interoperability. Mr. Zhou played key roles in and contributed regularly to standards groups, including IEC TC57 WG14, OAGi, and UN/CEFACT TMG, which defines standards for systems interoperability.

# The GridWise™ Olympic Peninsula Project Results

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The Olympic Peninsula Project was a field demonstration and test of advanced price signal-based control of distributed energy resources (DER). The project was part of the Pacific Northwest GridWise™ Testbed Demonstration, sponsored by the U.S. Department of Energy (DoE) and led by the Pacific Northwest National Laboratory. Other participating organizations included the Bonneville Power Administration, Public Utility District (PUD) #1 of Clallam County, the City of Port Angeles, Portland General Electric, IBM's T.J. Watson Research Center, Whirlpool, and Invensys Controls. The main objective of the project was to convert normally passive loads and idle distributed generation into actively participating resources that were optimally coordinated in near real-time to reduce stress on the local distribution system.

Planning began in late 2004 and the bulk of the development work took place in 2005. By late 2005 equipment installations began, and the experiment was fully operational by Spring 2006 and remained active full one full year.

The motivating theme of the project was the GridWise concept that inserting intelligence into electric-grid components at every point in the supply chain from generation through end-use will significantly improve both the electrical and economic efficiency of the power system. In this case information technology and communications was used to create a real-time energy market system that could control demand response automation and distributed generation dispatch. Optimal use of the DER assets was achieved through the market, which was designed to manage the flow of power through a constrained distribution feeder circuit.

The project also illustrated the value of interoperability in several ways, as defined by the DoE's GridWise Architecture Council (GWAC). First, a highly heterogeneous set of energy assets, associated automation controls, and business processes were composed into a single solution that integrated a purely economic or business function in the form of the market-clearing system with purely physical or operational functions in the form of thermostatic control of space heating and water

heating, demonstrating interoperability at the Technical and Informational levels of the GWAC Interoperability Framework (<http://www.gridwiseac.org/about/publications.aspx>). This is an ideal example of a cyber-physical-business system, and represents an important class of solutions that will emerge as part of the transition to smart grids.

Second, the objectives of the various asset owners participating in the market were continuously balanced to maintain the optimal solution at any point in time. This included the residential demand response customers, the commercial and municipal entities with both demand response and distributed generation, and the utilities, which demonstrated interoperability at the Organizational level of the Framework.

## Project resources

The following energy assets were configured to respond to market price signals:

- Residential demand response for electric space and water heating is 112 single family homes using gateways connected by either DSL or cable modem to provide two way communication. The residential demand response system allowed the current market price of electricity to be presented to customers. Consumers could also configure their demand response automation preferences. The residential consumers were evenly divided between three contract types (fixed, time of use, and real-time) and a fourth control group. All electricity consumption was metered, but only the loads in price-responsive homes were controlled by the project (~75 KW).
- Two distributed generation units (175 KW and 600 KW) at a commercial site served the facility's load when the feeder supply was not sufficient. These units were not connected in parallel to the grid, so they were bid into the market as a demand response asset equal to the total load of the facility (~170 KW). When the bid was satisfied, the facility disconnected from the grid and shifted its load to the distributed generation units.

- One distributed microturbine (30 KW) that was connected in parallel to the grid. This unit was bid into the market as a generation asset based on the actual fixed and variable expenses of running the unit.
- Five 40 HP water pumps, distributed between two municipal water pumping stations (~150 KW of total nameplate load). The demand response load from these pumps was incrementally bid into the market based on the water level in the pumped storage reservoir, effectively converting the top few feet of the reservoir capacity into a demand response asset on the electrical grid.

Monitoring was performed for all of these resources, and in cases of price-responsive contracts automated control of demand response was also provided. In all cases of automated control consumers were able to temporarily disable or override project control of their loads or generation units. In the residential real-time price demand response homes consumers were provided a simple configuration choice for their space heating and water heating that involved choosing an ideal set point, and choosing a degree of trade-off between comfort and price responsiveness.

For real-time price contracts, the space heater demand response involved automated bidding into the market by the space heating system. Since the programmable thermostats deployed in the project did not have any support for real-time market bidding, IBM Research implemented virtual thermostats in software using an event-based distributed programming prototype called Internet-scale Control Systems (iCS). iCS is designed to support distributed control applications that span virtually any underlying device or business process through the definition of software sensor, actuator, and control objects connected together by an asynchronous event programming model that can be deployed on a wide range of underlying communication and runtime environments. For this project, virtual thermostats were defined that conceptually wrapped the real thermostats and incorporated all the functionality of the real devices plus the additional functionality needed to implement the real-time bidding. These virtual thermostats received the actual temperature of the house as well as information about the real-time market average price and price distribution and the consumer's preferences for set point and comfort/economy trade-off setting. This allowed the virtual thermostats to calculate the appropriate bid every five minutes based on the changing temperature and market price of energy.

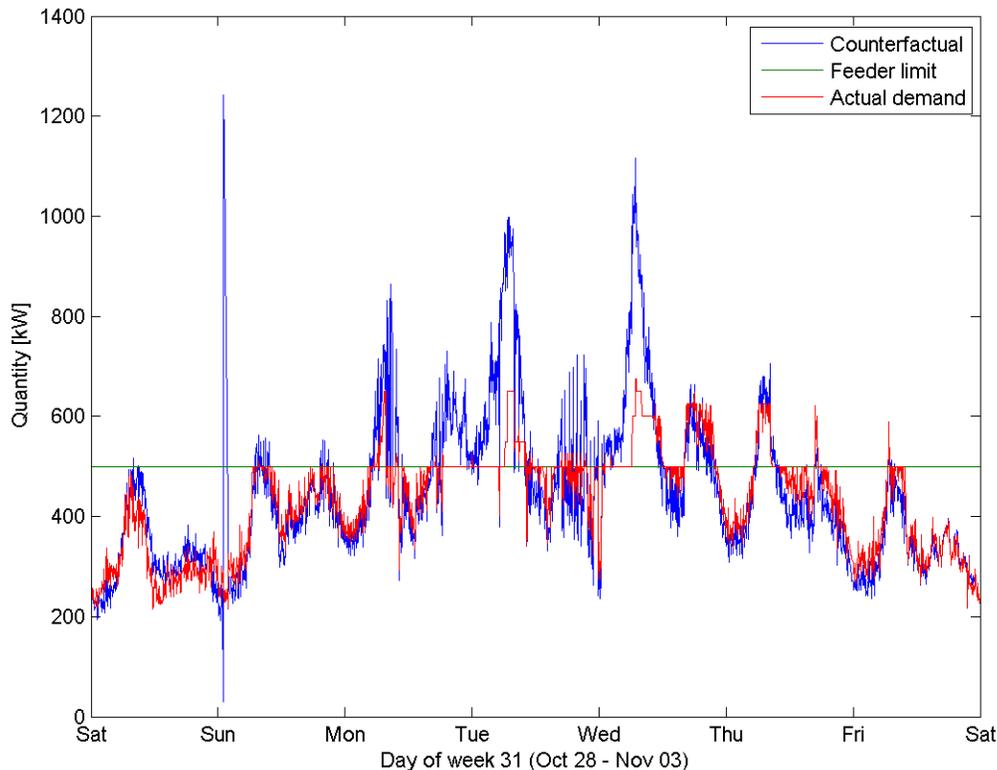
The real-time market in the project was implemented as a shadow market – that is, rather than change the actual utility billing structure, the project implemented a parallel billing system and a real-time market. Consumers still received their normal utility bill each month, but in addition they received an online bill from the shadow market. This additional bill was paid from a debit account that used funds seeded by the project based on historical energy consumption information for the consumer. The objective was to provide an economic incentive to the consumers to be more price responsive. This was accomplished by allowing the consumers to keep the remaining balance in the debit account at the end of each quarter. Those consumers who were most responsive were estimated to receive about \$150.00 at the end of the quarter.

The market in the project cleared every five minutes, having received demand response bids, distributed generation bids, and a base supply bid based on the supply capacity and wholesale price of energy in the Mid-Columbia system operated by Bonneville Power Administration (this was accomplished through a Dow Jones feed of the Mid-Columbia price and other information sources for capacity). The market operation required project assets to submit bids every five minutes into the market, and then respond to the cleared price at the end of the five minute market cycle. In the case of residential space heating in real-time price contract homes, the virtual thermostats adjusted the temperature set point every five minutes, but in most cases the adjustment was negligible (for example, 1/10<sup>th</sup> of a degree) if the price was stable.

### Key findings

**Distribution constraint management** – This was one of the primary objectives of the experiment, and was successfully accomplished. The distribution feeder imported capacity was managed through demand response automation to a cap of 750 KW for all but one five minute market cycle during the project year. In addition, distributed generation was dispatched as needed during the project, up to a peak of about 350 KW.

During one period of about 40 hours on October 30, 2006 to November 01, 2006 the system successfully constrained the feeder import capacity at its limit and dispatched distributed generation several times, as shown in Figure 1. In the figure, actual demand under real-time price control is shown in red, and the blue line shows what demand would have been without real-time price control. It should be noted that the red demand line steps up and down above the feeder



**Figure 1 Demand graph with and without real-time price controls**

capacity line several times during the event – this is the result of distributed generation units being dispatched and removed as their bid prices are met or not.

**Market-based control demonstrated** – The project controlled both heating and cooling loads, which showed a surprisingly significant shift in energy consumption. Space conditioning loads in real-time price contract homes demonstrated a significant shift to early morning hours. This occurred during both constrained and unconstrained feeder conditions, but was more pronounced during constrained periods. This result is similar to what one would expect in pre-heating or pre-cooling systems, but the neither the real nor the virtual thermostats in the project had any explicit prediction capability. The analysis showed that the diurnal shape of the price curve itself caused the effect.

**Peak load reduced** – The project’s real-time price control system both deferred and shifted peak load very effectively. Unlike the time of use system, the real-time price control system operated at a much finer level of precision, responding only when constraints were present, and resulting in a very precise and proportionally appropriate level of

response. The time of use system, on the other hand, was much coarser in its response, and also responded regardless conditions on the grid, since it was only responding to pre-configured time schedules or manually initiated Critical Peak Price signals.

**Internet-Based control demonstrated** – Bids and control of the distributed energy resources in the project were implemented over Internet connections. As an example, the residential thermostats modified their operation through a combination of local and central control communicated as asynchronous events over the Internet. Even in situations of intermittent communication failure, resources typically performed well in default mode until communications could be re-established. This example of the resilience of a well-designed, loosely coupled distributed control application schema is an important aspect of what the project demonstrated.

**Distributed generation served as a valuable resource** – The project was very effective in using the distributed generation units, and dispatched them many times over the duration of the experiment. Since the diesel generators were restricted by environmental licensing regulations to operate no more than 100 hours per year, the bid calculation factored in a sliding scale price premium such that

bids would become higher as the cumulative runtime for the generators increased toward 100 hours.

### **Conclusion**

The Olympic Peninsula project was a unique in many ways. It clearly demonstrated the value of the GridWise concepts of leveraging information technology and incorporating market constructs for managing distributed energy resources. Local marginal price signals as implemented through the market clearing process and the overall event-based software integration framework successfully managed the bidding and dispatch of loads and balanced the issues of wholesale costs, distribution congestion, and customer needs in a very natural fashion.

The final report on the project is available at <http://www.gridwise.pnl.gov>, along with other background material. The report expands on the remarks in this article, and covers in detail a number of important assertions that the project supported, including:

- Market-based control was shown to be a viable and effective tool for managing price-based responses from single-family premises.
- Peak load reduction was successfully accomplished.
- Automation was extremely important for obtaining consistent responses from both supply and demand resources.
- The project demonstrated that demand response programs could be designed by establishing debit account incentives without changing the actual energy prices offered by energy providers.

Although technological challenges were identified and noted, the project found no fundamental obstacles to implementing similar systems at a much larger scale, and it is hoped that an opportunity to do so will present itself at some point in the near future.

### **Biography**

*Ron Ambrosio, IBM Global Research Leader, Energy & Utilities Industry, IBM T.J. Watson Research Center*

Ron Ambrosio is a Senior Technical Staff Member responsible for IBM's research activities in Energy & Utilities across the company's eight world-wide Research Division laboratories. He is also a member of the U.S. Dept. of Energy's GridWise Architecture Council. His research areas include embedded systems and distributed application environments, with particular emphasis on Cyber-Physical Business Systems or the integration of sensor and control system environments with business process environments.

# Enabling Cost-Effective Distribution Automation through Open Standards AMI Communication

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**Keywords:** Distribution Automation, C12.22,

## **Abstract**

Advanced Metering Infrastructure (AMI) is well recognized as the foundational technology platform enabling the Smart Grid of the future. Often, it is the first milestone in connecting utilities to the Smart Grid. Not only does AMI provide significant features and functions that enable a wide variety of Smart Grid applications, but it brings with it a communications infrastructure that transcends the electric utility service territory, extending the network to the millions of consumers at the edges of the delivery system. With this comes a potential economy of scale to support additional, low-cost monitoring and control applications that historically have not been practical due to communication costs. At the same time, underlying strategic elements that contribute to the vision of the Smart Grid also drive requirements for increased visibility into the status of the power delivery infrastructure and operational awareness for the optimization of the delivery and use of energy.

This combination of conditions has stimulated a revitalized interest in Distribution Automation (DA), which is being viewed as the next logical Smart Grid milestone after AMI. As a result, utilities are beginning to contrast the cost of a standalone Distribution Automation infrastructure with that of an AMI solution coupled with a DA deployment that leverages the synergies of a common communication platform.

The ANSI C12.22 protocol is integral to creating that common communication platform. C12.22 is an open standard focused on the application layer of the network. It was designed specifically for communicating utility device data across any network medium. In particular, it is well suited to support high-latency DA devices where response time requirements are not as stringent (30 to 90 seconds), where there is large population of devices, and where communication costs are a greater consideration.

## **1. STANDARDS**

As a reference for understanding this document, a high level primer with associated definitions follow:

### **1.1. ANSI C12.19**

ANSI C12.19 is a standards specification for utility industry end-device data tables. The specification was initially ratified in 1997 and defines the model for passing data to and from end devices. C12.19 ‘tables’ are nothing more than templates for transporting data. It is a form that represents an ordered list of information. One analogy that best describes this is an individual’s income tax return form. A tax form says nothing about how your records should be kept. Your information can be stored on separate sheets of paper, in a binder, in your computer, or in a mason jar. However, the tax form does require that the data be presented properly and in a specific order. Similarly, the predefined tables in C12.19 do not impose how the data is stored. The end device only needs to create the data in the proper form and order when requested to deliver information, and accept information in the proper form and order when it arrives.

### **1.2. ANSI C12.22**

C12.22 is primarily an application protocol. It extends C12.19 to support reliable data network communications at the end-device. The protocol defines how to transport C12.19-format data over a network using the OSI (Open Systems Interconnect) model.

Uses of the protocol include operation over the C12.22 node network, and a point-to-point interface between a C12.22 device and a C12.22 communications module (network adaptor). C12.22 offers a methodology for both session and session less communications. In addition it provides for

- common data encryption and security
- a common addressing mechanism for use over both proprietary and non-proprietary network mediums
- interoperability among end devices within a common communication environment
- system integration with third-party devices through common interfaces
- both 2-way and 1-way communications with end devices

- enhanced security, reliability and speed for transferring end-device data over heterogeneous networks

## 2. ANSI C12.22 WITHIN THE INTEROPERABILITY FRAMEWORK

ANSI C12.22 can be further characterized within the interoperability context-setting framework defined by the GridWise Architecture Counsel<sup>1</sup>. The framework divides the concept of interoperability into eight key levels. C12.22 focuses on levels two and three, Network Interoperability and Syntactic Interoperability.

C12.22 provides network interoperability by abstracting communications to the application layer of the OSI network model. In doing so, it allows for the transport of data over virtually any type of networking medium. Thus a C12.22-compliant message can travel across an radio-frequency mesh network to reach a collection point, then move along a fiber optic network to reach the utility, and then traverse the Category 5 Ethernet cabling inside the utility to reach its destination.

C12.22 provides syntactic interoperability through its symbiosis with C12.19 data structures. That standard defines the structure of messages exchanged between systems. Thus different types of devices can exchange information across a network if they all use the C12.19 standard to structure the information they share.

## 3. ANSI C12.22 NETWORK TOPOLOGY

C12.22 protocol spans an entire network and enables multiple types of devices.

### 3.1. ANSI C12.22 Master Relay

A C12.22 Master Relay operates at the top of a hierarchy of relays. It provides registration services for all devices in its

domain. It is also responsible for issuing registration service queries to C12.22 Authentication Hosts and de-registration service requests and notifications to C12.22 Notification Hosts when registering a C12.22 Node. A C12.22 Master Relay can also act as a C12.22 Host.

### 3.2. ANSI C12.22 Relay

A C12.22 Relay is a node that provides address resolution, datagram segmentation and optionally message forwarding services to other C12.22 Nodes. Address resolution services consist of mapping Layer 7 addresses (ApTitle) to lower layer addresses.

### 3.3. ANSI C12.22 Device

A Device hosts C12.22 Application(s) and provides at least one interface to a C12.22 Communication Module.

### 3.4. ANSI C12.22 Gateway

A C12.22 Gateway translates the ANSI Standard C12.22 protocol to and from other protocols. Gateways are required when a C12.22 Node needs to communicate with non-C12.22 nodes. C12.22 Gateways can be attached directly to the non-C12.22 devices or they can provide their translation services through any network segment (DNP3/C12.22 Gateway).

### 3.5. ANSI C12.22 Node

A Node attaches to a C12.22 network segment and contains a C12.22 Communications Module, one or more C12.22 Applications, and possibly C12.19 data table structures.

### 3.6. ANSI C12.22 Communications Module

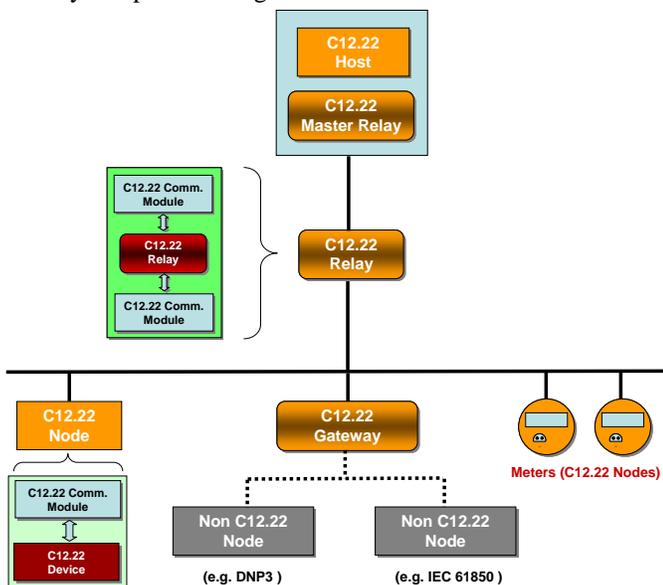
A Communications Module attaches a C12.22 Device to a C12.22 Network Segment. A C12.22 Communication Module can be physically located inside or outside the C12.22 Device enclosure. However, it is physically and logically distinct from the C12.22 Device. The interface between the C12.22 Communication Module and the C12.22 Device is completely defined by the C.12.22 Standard. The combination of a C12.22 Device and a C12.22 Communication module constitutes a C12.22 Node. If a C12.22 Communication Module contains Tables, it is also a C12.22 Node.

### 3.7. ANSI C12.22 Application

An Application Entity that implements a set of services and procedures as defined in the C12.22 Standard, permitting one or more well-defined devices (C12.22 Host, C12.22 Relay, C12.22 Device, C12.22 Communication Module, etc.) to interact within the framework of a C12.22 Network. It may also contain C12.19 Tables.

### 3.8. ANSI C12.19 Device

A C12.22 Node that contains C12.19 data table structures.



## **4. METHODS OF INTERGRATING C12.22 INTO DISTRIBUTION AUTOMATION DEVICES**

There are three primary methods for integrating c12.22 into distribution automation devices.

### **4.1. Metrology Integration**

For leveraging standard radio-frequency LAN communications and electricity metrology, emulating the metrology C12.22 Blurt message could be the most straightforward and cost effective approach for equipping DA devices with C12.22 communications. Practical applications would most likely be for non-revenue metering appliances such as transformer and feeder metering and low cost sensing devices.

The following diagram shows integration with a non-revenue metering application, feeder metering.

### **4.2. C12.22 Device**

C12.22 defines an RJ11 connector for the Physical Layer on local ports. This architecture also allows development of C12.22 Communication Modules that can interface any C12.22 Device to specific networks. A C12.22 Device plus a C12.22 Communication Module arranged in this fashion constitutes a C12.22 Node. The C12.22 Transport and Datalink layers are used between the third-party C12.22 Device and Communication Module. The details of the C12.22 Device and C12.22 Communications Module are defined in Section 6 of the ANSI C12.22-2008 specification.

### **4.3. Gateway**

A C12.22 Gateway is a C12.22 Node that translates the ANSI Standard C12.22 protocol to/from other protocols. Gateways are required when a C12.22 Node needs to communicate with non-C12.22 Nodes. C12.22 Gateways can be attached directly to the non-C12.22 devices or they can provide their translation services through any network segment.

## **5. SAMPLE APPLICATIONS**

There are several sample applications for using C12.22 communications for distribution automation.

### **5.1. Smart Fault Indicators**

A Smart Gird should supply actual outage and restoration notification at the feeder and lateral level. Fault indicators equipped with C12.22 communications can provide this information. With proper IT integration at the utility back office, circuit segment outage information from the outage management system can be correlated with outage notification from AMI systems to offer more comprehensive understanding of an outage's scope. Once open standards communications exist at the distribution level, several sources of information open up. Real-time fault detectors record fault current events, by circuit and phase, down to the

sensor span level. Fault waveforms and propagation sequencing by sensors can be made available for detailed post analysis. Real-time knowledge of the state of the distribution system is essential for safe automated or manual switching in service restoration work. Better information helps field crews be more efficient in restoring power, which reduces SAIDI scores. In addition, continuous load monitoring provides accurate data to support short- and long-term decisions on load balance and capacity upgrades.

### **5.2. Capacitor Bank Control**

C12.22 can provide the communications protocol for capacitor bank monitoring and remote control in electric distribution systems.

### **5.3. Automated Network Protector Status Indication**

C12.22 communication can enable remote monitoring of the events and status of self-powered, electronically-controlled, dropout circuit protectors. These devices eliminate permanent outages that can result when lateral fuses operate in response to momentary faults. These circuit protectors also eliminate momentary interruptions along feeders in cases where a substation breaker opens to save the lateral fuse during a momentary fault.

### **5.4. Automated Throw-Over Status Indication**

Remote monitoring through C12.22 communications can be applied to circuit interruption switch events for overhead distribution feeders. This applies to either group-operated or single-pole applications.

### **5.5. Transformer/Feeder Metering**

Theft diversion solution that incorporates transformer and feeder metrology integrated with AMI metering and communication technology. This example incorporates distribution transformer meters and feeder meters within the AMI solution architecture to provide the required data to allow for identification of potential diversion. The device will function like a meter and provide profiled energy and voltage measurements that can be used to compare against the aggregate of the meters installed downstream of the distribution transformer. The device can also be used to provide transformer aging data such as temperature.

## **6. DEMAND RESPONSE ANALOGY**

Please include options for implementing the ANSI standard in both domains and any adaptations required for applying the standard.

Distribution automation shares interoperability aspects with another technology gaining acceptance in the utility world, demand response.

Demand response entails consumers changing their consumption behavior in response to system status or price

signals. Informing consumers on time-based rates that the price of energy has changed and allowing consumers to then adjust their consumption is a prevalent form of demand response. Consumers can automate their response, given control equipment that also communicates. One example is a programmable communicating thermostat that receives price signals from the utility and responds to those signals according to the preferences set by the consumer.

So it is with distribution automation as well. Both processes involve communicating information about the power system and providing for automated response based on that information. Both distribution automation and demand response require interoperability to integrate into a utility's existing and future infrastructure.

The sample distribution automation applications discussed in this paper share similar response latency timeframes with demand response. As such, they can also share similar network infrastructures for communications. Since C12.22 and C12.19 pertain to data structure and communications, they can be integrated into both distribution automation and demand response devices.

## **7. CONCLUSION**

As utilities invest huge sums into capital projects to build out the promise of the Smart Grid, they are increasingly demanding open standards in part to protect those investments from obsolescence or overdependence on one vendor's proprietary technology. In response, the AMI market has undertaken rapid adoption of open standards such as ZigBee®, ANSI C12.19, Internet Protocol, WSDL, SOAP, and more. C12.22 is an open standard communications protocol that can help utilities invest in cost-effective distribution automation.

### **Biography**

Mike Burns is responsible for guiding the Smart Grid strategy at Itron, Inc. In this role, Mike participates in a number of national level working groups and initiatives aimed at building consensus and understanding around the Smart Grid vision.

Before rejoining Itron in 2006, he was Chief Business Development Officer for MicroPlanet Technology Corp., a Seattle based energy efficiency technology company.

Mike served as a Submarine Officer in the Navy, and holds a BS in Economics from the United States Naval Academy.

<sup>i</sup> "Interoperability Context-Setting Framework," GridWise Architecture Council, July 2007

# Issues and Options for Advanced Networking Infrastructure for Energy Systems

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**Keywords:** Internet, internet protocols, IP, TCP, Inter Process Communications, Network Management

## Abstract

The Internet Protocols characterized by Transmission Control Protocol (TCP)/Internet Protocol (IP) and the supporting RFC's for designing and implementing systems were developed in the 1970's and codified into standards at that time. IPv4 has known weaknesses in address space and other functions that are needed by energy industry networks. IPv6 has been a work in progress for nearly 15 years. Concerns surrounding the adoption of the Internet Protocols include the number of supporting RFC's and possible configurations as well as the management issues that could arise surrounding independent implementations of the suite. Issues surrounding multihoming, mobility, quality of service and security management will be necessary to resolve for critical energy applications. Some of the possible options for networks that must meet stringent Quality of Service (QoS), security and management functions in real-time environments are proposed from design simplifications based on an interprocess communications (IPC) model.

## 1. POWER INDUSTRY HAS UNIQUE NETWORKING AND MANAGEMENT REQUIREMENTS

Communication networks are key to the operation of an electric utility and these networks have unique requirements not found in typical enterprise information system networks. Beyond the "simple" task of moving data between all of the necessary kinds of equipment, utility networks have unique requirements for security and availability, as well as requirements for the ability to respond quickly and effectively to fast changing conditions. Security and availability are critical in a utility network. Unauthorized access, denial of service attacks, viruses could easily impair or disrupt operation and cause wide spread outages. Similarly, equipment failures or disruptions due to natural or man-made disasters could take down parts of the network. It is critical that it be possible to still communicate

with key points in the utility systems and quickly re-configure the network to meet new conditions. These requirements point to industrial strength capabilities in a network infrastructure

## 2. ADOPTION OF TECHNOLOGY

The power industry is an industry of adoption of technology. Many of the standards that are part of the key advanced automation standards have their origins in other industries. Adoption of technology makes sense since it saves development time and connects the power industry with other areas of expertise. The Internet is presently used widely in the power industry for typical business functions such as email, web browsing and simpler web based functions that allow customers to access information from their local utility websites. All of these uses of the Internet Protocols are useful and valuable to the industry. Since a good deal of effort went into their development, the question has been raised: "Can't we make use of the internet protocols for developing networks for power systems communications and control?" The current state of the Internet Protocols are the subject of recent study and concern by the industry. While some technical issues have been addressed others remain to be solved as well as achieving the maturity required for critical energy industry applications.

### 2.1. The Layered Paradigm

The early development of networking quickly adopted the software approach of layering to manage the complexity of these systems. Because network protocols created shared state with different scope, layering was even more appropriate than in software systems. This provided a discipline and common nomenclature for design. By the mid-1970s, the definition of a physical, data link, network and transport layers and their roles were fairly well established. It was less clear what was above that. Beginning in 1978, Open Systems Interconnect (OSI) created the OSI Basic Reference Model proposing that the

Session, Presentation, and Application Layers on top. But by 1983, OSI had found that these 3 layers were really functions of a single Application Layer, even though politics prevented them from revising the BRM. The protocols were defined so that they could be implemented as a single layer. In addition, developments in the lower layers indicated that data link and network layers were richer than first suspected and “sub-layers” appeared there. During the 1980s, the OSI BRM based layered approach came under wide-spread criticism because of naïve implementations and the state of our knowledge.

The 20 year drought of new applications brought the Internet community to more or less the same conclusion as OSI. . Internet development centered on the Transmission Control Protocol/Internet Protocol (TCP/IP) and mostly avoided what was above or below it. This stack is in widespread use today for the Internet. TCP/IP was proposed in 1974 and finally codified by the DoD in the early 1980’s. TCP/IP and the other standards associated with the Internet were developed for sharing information with research institutions and networks when it first started. It was not designed for the large scale system now characterized by the World Wide Web. Nor was it designed for the types of applications that are now being deployed. The Internet was never intended for its current role. In fact, major unanswered issues uncovered by the mid-70s remain unanswered. Only the effects of Moore’s Law have avoided major calamity. As it turns out this is not easy since the architecture of the Internet and the internet protocols have some weaknesses that are still being worked on [2].

## 2.2. Challenges in Retrofit Architecture

The internet protocols have needed to evolve over time to accommodate the unprecedented scale and scope that the Internet has become today. However, this does not mean things got simpler. For example the Internet Protocol (IP) is a key protocol in the middle of the stack that establishes the rules for routing messages and addressing them. IP version 4, the one now in widespread use was not designed to accommodate the addressing requirements of even early networks, let alone current ones. Network engineers began to develop the next generation IP version 6 about 15 years ago but this solves the least of the problems: providing more addresses. In addition to address space the internet suite of standards also needs some additional advanced capabilities such as Quality of Service, multihoming, mobility, robust management and security. These advanced functions are being specified through a series of additional specifications, that can only be described generously as patches. The concern is that these specifications, known as Requests for Comments, and now number now over 100 documents [1] will increase the “parts count” and complexity so that not only are there are several possible configurations but unforeseen interactions among these patches. There are a

number of issues surrounding how to migrate from the older IPv4 to the newer IPv6 while maintaining the ability to manage and secure networks built to both. Moreover, the management of the large number of parts to build and secure the types of industrial strength networking utilities will need will be a challenging task. There are also concerns that we may not be able to build up an industrial strength network, that meets all the requirements of advanced automation with the older architecture of the internet standards. Concerns have been expressed by CAIDA and others in the further adoption of the Internet for critical applications

## 2.3. A Few of the Next Generation Networking Needs and Challenges

While the Internet has put considerable effort into a “one size fits all” approach and to ensuring fairness to all users, based on a “best effort” model that can not support “real-time” applications. Real time applications are those that must execute within a defined window of time. If the application does not execute within the specified time window the application fails. Energy service and utility networks have a distinct requirement for many applications to deliver controlled access to network resources to support applications that have real time requirements. Many power engineering and system “protection” applications have real-time requirements.<sup>1</sup> The networking concept of “Quality of Service” (QoS) sets up a method of prioritizing network resources for this purpose, enabling some applications to have preference for network resources to ensure that the communication packets get through to meet requirements. This sets up a system of “unfairness.” Or put in more traditional terms, utility networks must provide guaranteed quality of service (QoS) to groups of users and in some circumstances denying service to some users. Providing different levels of QoS is by its nature “unfair” as the term is used in Internet circles. Much of the responsibility of ensuring this capability resides with network management. Hence, effective network management is crucial to the success of utility networks.

Security of internet protocol based implementations has been a subject of study for over two decades. The original focus of the TCP/IP networks was largely on the functions of networking and not on a security infrastructure. This meant that security vulnerabilities have been identified in TCP/IP implementations. Some were specific to local implementations while others were inherent in the protocols themselves and thus potentially impacting any system [2]. As recently as just a few months ago fundamental weaknesses in the protocols were still being

<sup>1</sup> This said, we must note that real-time requirements should be done with minimal range. Attempting real-time service over a wide area is, in effect, creating a single point of failure and dangerous.

discovered. [2] Given the number of RFC's that must be supported the management of security will be difficult to support from multiple vendor implementations. Security with implementations based on TCP/IP stacks remains a topic for further investigation for security robustness. A secure implementation of a TCP/IP profile is reported to be a very difficult task since no one document provides the needed guidance. The number of options that are in approved RFC's as well as those that are not formally stated adds to the challenge of creating a fully secure TCP/IP implementation even without consideration of integration with different vendors. Keeping in mind that researchers have known for 30 years that retrofitting security into complex systems was futile.

Additional advanced networking capabilities are needed for power industry communications including functions such as multihoming, multicast, anycast, distributed application addressing, and private addressing. In addition the power industry needs strong network and systems management capabilities since the power delivery infrastructure will be critically dependent on the communications infrastructure.

To effectively manage large networks there are a small number of critical characteristics that need to be supported:

- scalability-the ability to scale up to millions of connected devices and networks
- repeatability-the ability to construct systems using standardized components and approaches rather than using customized elements and work arounds
- orthogonality-the characteristic of distinctly separate elements of the network that are independent of common elements
- commonality-a characteristic that enables the integration of different systems and equipment into a common networking framework

These characteristics cannot be executed through multiple vendor implementations of the existing variety of TCP/IP supporting documents alone. One of the big challenges is the parts count that is implied by the number of proposed work-arounds and proposed security patches. All of this has lead to the admission that the Internet architecture is out of steam, that in fact it has more in common with something like DOS than say Unix or Windows.

#### **2.4. A New Paradigm For Networking**

Luckily one of us has been thinking about this problem and after years of careful consideration has backed out of the blind alley we turned down 25 years ago and uncovered a new simpler paradigm for networking that scales [4]. The new paradigm distills and reorganizes previous models to

the concept of Inter Process Communications (IPC). This concept sees the network as the set of functions needed to provide IPC, basically collapsing the stack down to a single layer that repeats with different policies. This approach to networking creates a complexity collapse and the repeating structure greatly simplifies manageability. Many of the additions necessary in the TCP/IP stack are a consequence of the structure in the IPC based model. Capabilities such as multihoming, mobility, private addressing, and many aspects of security and network management, are inherent in the IPC model. Appropriate policies in the IPC layers not only allows Quality of Service to be done, but effectively managed through the implementation policies. The researchers noted these recurring patterns in basic data communications and now posit this model as a way of simplifying the parts count in networks and improving the ability to manage the network. A number of issues in the older paradigm are solved with the elegance of a simplified model. Readers are encouraged to go deeper into this topic in reference [4]

#### **2.5. Networking Technology Research and Development**

At this point additional research is needed to develop designs and implementations that can test the new model of networking. The IPC model represents a general theory of networking that needs to be further explored. The theory promises a variety of key networking functions that can be met without the complexity of what is proposed by the TCP/IP stack today.

#### **2.6. Conclusion**

The power industry needs to substantially understand its requirements for managing and scaling networks that will be used for real-time and critical power control communications. These requirements in turn will enable the industry to appropriately adopt technology from other industries as well as understanding the characteristics that are critical for power system communications operations. The IPC model represents key research into alternatives necessary to investigate for critical power industry operations. Inter Process Communication paradigm for networking represents a substantial amount of study on the recurring patterns seen within the older layers. The promise of simplified network infrastructures that include the ability to support key networking functions such as multihoming, mobility, robust management and security warrants a closer look. The IPC networking paradigm and theories are candidates for further investigation for the nations critical infrastructures.

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### Biography

Joe Hughes has a background of over 30 years in the power industry including 25 in research and development. He holds a bachelors degree in physical science and a masters in computer systems.

John Day has been involved with advanced computer networking research, operating system development and parallel processing since 1970. John was originally involved in the design of protocols for ARPANET and the Internet. He has pioneered the development of network management architectures.

# Smart AMI Solutions Enable the Smart Grid

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**Keywords:** Smart Grid, Advanced Meter Infrastructure, AMI, Electric, Water, Gas, Utility, Energy, Smart Network, Wireless, Mesh, Secure, AMR

## Abstract

As utilities adopt Smart Grid technologies, interoperability between meters, software solutions and the communications networks upon which they are based become increasingly critical to both grid health and the bottom line. An intelligent power distribution network demands communications platforms and systems of systems that can exchange information across technologies and continuously adjust to meet the changing needs of utilities and their customers. With thousands of utilities scattered across the U.S. alone, the Smart Grid requires the myriad new and legacy information systems they are employing be easily and cost-effectively integrated for a truly interoperable grid. We review here the opportunities and benefits of employing an interoperable communications network to overcome the cost barrier at its most basic level. Discover the architectural approach that will deliver the flexibility and functionality to allow utilities to consistently adopt interoperable solutions, reduce ongoing operation costs and deliver faster ROI. We further lay the groundwork for the Smart Grid with an interoperable platform supporting both existing and emerging advanced capabilities including: smart metering, demand response, and home area networking.

## 1. INTRODUCTION

On a continuous basis, utilities are challenged to meet the growth of peak energy demands, soaring costs, along with managing the operational risks of resource location combined with unprecedented environmental constraints. Since 1990, electricity demand has increased approximately 25 percent in the United States. Simultaneously, transmission construction has dropped by almost one-third. Losses in the U.S. economy due to power outages and power quality disturbances are estimated to be between \$119 billion and \$188 billion annually (“The Value of Electricity When It’s Not Available”, NREL, 2003).

The Department of Energy estimates that over 280 gigawatts of new generating capacity will be needed by 2025. To meet this projected capacity, 937 new 300-megawatt power plants would need to be built which are not

currently planned. The need for new plants, maintaining overburdened infrastructure, coping with an aging workforce, complying with regulations, and environmental concerns are the critical issues facing the energy industry today.

Since its inception, the energy industry has rightfully focused on the supply side of this challenge, but sophisticated technologies such as mesh networking now exist which can significantly impact the demand side of the equation. When used as the backbone of an Advanced Metering Infrastructure (AMI) solution, mesh networking enables two-way intelligent networked communications with smart meters that enables command and control for value added services like demand response and demand side management, besides meter reading. Interoperable networks and systems across the entire power infrastructure aid in the management and control of energy consumption, improve operations management, conserve the environment, and adhere to evolving regulations.

The potential of Smart Grid and its market benefits are essential for achieving energy efficiency and maintaining the competitive state of utility services. A self configuring, autonomously managing, self healing grid network architecture is necessary to enable interoperable solutions and cost-effectively protect revenues today, while laying the foundations for future services.

## 2. IMPROVING ENERGY EFFICIENCY

AMI Network is the building block for an efficient and interoperable Smart Grid. It delivers valuable grid information for better energy-management decisions by utilities. With AMI Networks, utilities can analyze frequent interval data to offer time-based rates and demand management programs enabling them to deal with ever increasing demand and stretched system capacities. When offered these energy alternatives, consumers become aware of their own carbon footprints and are eager to participate in energy efficiency and conservation programs.

A long list of benefits emerges when utilities leverage interoperable network solutions to monitor the grid and automate distribution system equipment. For instance, AMI networks can identify chronically overloaded or underutilized assets, so utilities can upgrade where needed

and redeploy as necessary. The ability of such networks to assist in data tracking and analysis of usage patterns enables sustainable generation and procurement programs that directly boost utility profits.

Likewise, AMI network solutions permit early detection of outages before they spread, and help identify system balancing needs and power-quality problems such as voltage sags or spikes. They assist to identify and prioritize asset management initiatives and improve overall workforce efficiencies. The asset monitoring, energy management and diagnostic capabilities of Smart AMI networks when combined with innovative customer services lead to the primary goal of a Smart Grid - a robust, self-healing energy infrastructure.

### 3. REGULATORY COMPLIANCE WITH ECONOMIC GAINS

Smart Grid policies, tax-incentives, and legislation continue to drive deployment of AMI Network solutions independent of economic justifications. Regulators have many good reasons for directing utility actions, including fairness, customer value, and quality of service.

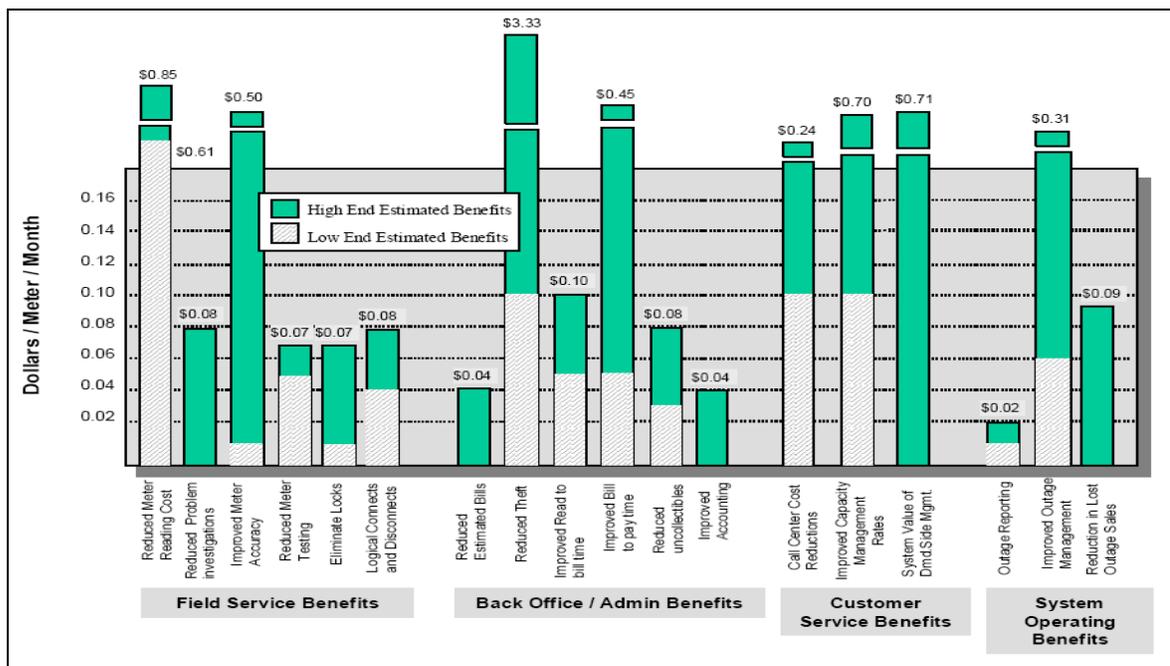
The energy act of 2007 is a policy statement motivated by the broad interest of America as a whole. The act makes it official policy of the nation to encourage time-based pricing and other forms of demand response. To that end, state

utility commissions are mandated to consider implementation of time-based rates and advanced metering solutions.

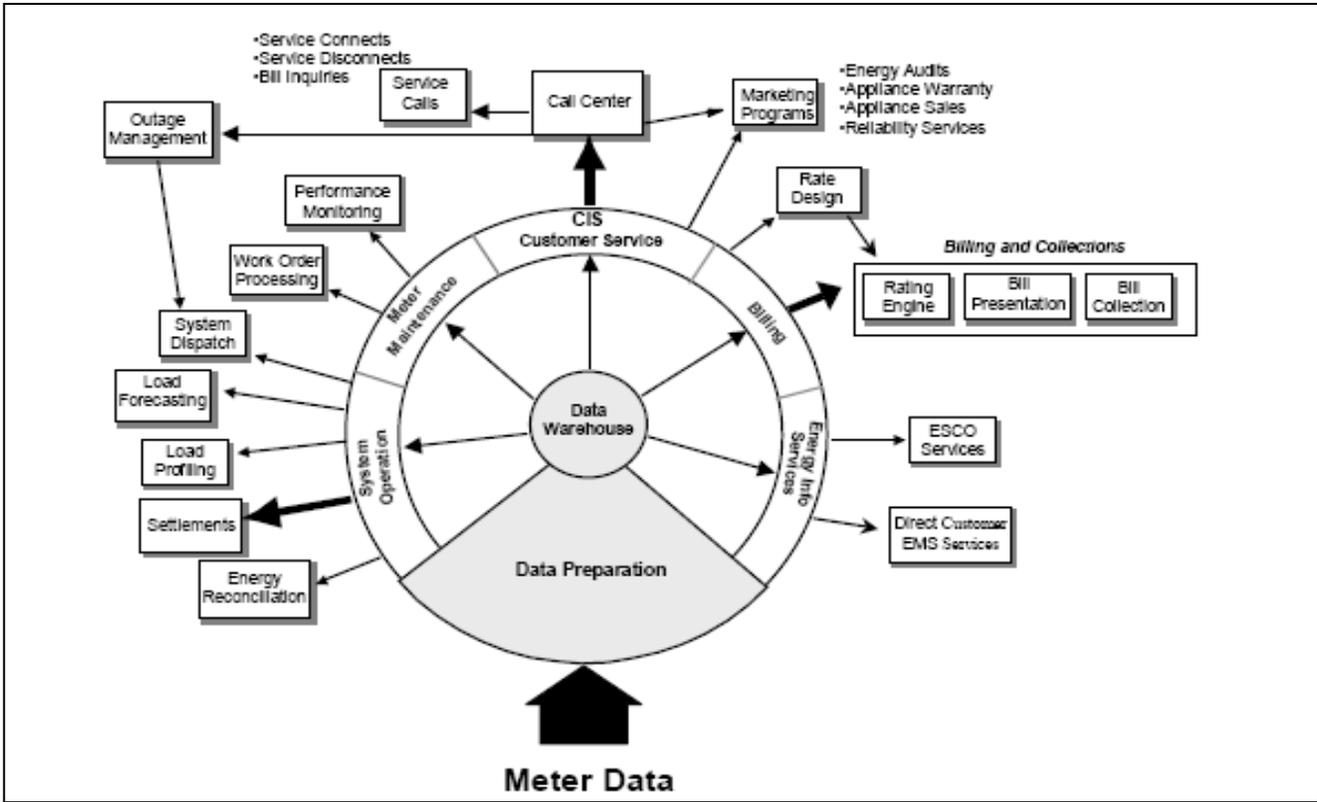
Not surprisingly, there is increased interest in demand response programs that could cut peak loads and reduce the need for peaking capacity. Many utilities, without any regulatory imperative, will continue deploying AMI Network systems simply because they reduce costs and improve the quality of service to consumers. The recent flood of advanced metering RFPs across all utility segments is a direct testament to this positive trend.

Regulated utilities in California are preparing to deploy large scale AMI networks, with full realization of costs and benefits as shown in Figure-1. This data was compiled and published by the California Energy Commission in the Meter Scoping Study report. The analysis includes four different perspectives in addressing the cost/benefit equation from least cost and savings to profitability and as a competitive enabler for future services.

The discrete benefits, as shown in Figure 1, provide additional opportunities beyond the meter with integration of ‘data’ that flows across all utility functions as shown in Figure-2.



Source: California Energy Commission, Meter Scoping Study – **Figure 1 Typical AMI Systems Benefits**



Source: California Energy Commission Meter Scoping Study - **Figure-2: Interoperable Utility Operations**

New cost savings result by eliminating the need for expensive and duplicate or parallel sources between operating units to deliver existing and new services. Even the low-benefit level provides a net reduction per month in system costs, regardless of the contract term as per the study.

This revealing study and the regulatory initiative by California is an aggressive and innovative step, seeking to promote customer awareness of peak load periods and positively influencing their response to peak-sensitive pricing, reducing the recurring likelihood of the rolling blackouts of year 2000. It is policy, developed in a consensus process with legislators, utilities, regulators, businesses, and consumer advocates, that is driving this effort forward. However, there is more than just policy pushing Smart Grid initiatives into overdrive.

**4. FOUNDATIONS OF SMART AMI**

The Meter Scoping Study illustrates the value and potential of Smart AMI Networks -- a solution that benefits the consumer, the environment, and the power grid. Strategic commitment and investments in smart meter networks are needed now to enable the Smart Grid. With AMI

technology, utilities will be prepared for a new way of improving their businesses tomorrow.

In meeting these challenges, Smart AMI Networks have emerged as the solution of choice across all utilities. Proven in implementations around the world, smart networks are an integrated AMI solution that includes all the hardware, software, and tools needed to quickly and economically deploy an advanced metering platform. Smart network solutions employ an intelligent wireless mesh technology that offers significant economic and technology advantages for advanced metering and energy infrastructure automation applications. They are cost-effective and scale by design from thousands to hundreds of thousands of endpoints without intervention, hierarchy or complexity.

Interoperable architectures deliver the benefits of Smart AMI Networks. Built on a system of systems approach, Smart AMI Networks integrate and interoperate across Home Area Networks (HAN), AMI Network(s), Wide Area Networks (WANs), and Enterprise Networks. Each of these networks operates independently within their functional environments and still delivers end-to-end interoperability with open standards and technology.

End-to-end interoperability is achieved across three distinct levels – Services, Applications, and Networks. Services are end to end in nature and touch multiple systems. For, example although HAN services interact with devices in the home, they may still need data from the AMI network and from Enterprise Networks both utility owned and/or third party networks. Applications are specific programs within a service domain. In the case of HAN, Demand Response, Load Control, Plug-In-Hybrids, etc. are specific applications. Like wise, meter data related applications will fall under AMI service domain. Interoperability across networks is achieved at the ‘cloud’ level. The Common Information Model (CIM) framework is the guiding principle across systems within an AMI network. ZigBee/HomePlug Smart Energy Profile is the emerging standard in the HAN. WAN technologies are very mature and sophisticated to accommodate universal IP across multiple media technologies. At the enterprise level, SOAP, XML, Web Services and MultiSpeak are being deployed. Transmission & Distribution, Distributed Automation and Substation Automation systems will also be integrated for interoperability as the Smart Grid matures. Network Management interoperability is also achieved at multiple levels across the various networks through open standards and application level management data. Interoperability standards also support the future application layering necessary to serve evolving utility and customer needs.

## 5. THE SMART AMI NETWORK SOLUTION

With ongoing advances in communications, cost-effective smart networking is the key driver for expanded AMI deployment throughout utilities. But technology is only an enabler -- the true value of AMI lies in its abilities to improve a utility’s operations, forecasting, and demand management while simultaneously providing alternatives to consumers in managing their energy usage and budgets.

Smart networks expand the technology of electrical grids by adding components such as self-managing and self-healing mesh networking, intelligent meters, and bridging to Home Area Networks (HAN) for connectivity to energy consuming appliances. Smart meters communicate in near real-time with the utility, providing detailed usage data while also receiving and displaying TOU pricing information, and offering other on-demand abilities such as remote connect/disconnect, unrestricted monitoring and control, etc. These capabilities enable customers with the precise data for tailoring consumption, minimizing energy expenses, while helping balance overall network demand.

Utilities value Smart AMI Network solutions as an avenue to forecast and manage energy usage during peak demand periods and also as an essential tool in maximizing

operational efficiencies to boost bottom line performance with its:

- Low cost of management and maintenance - Smart networks are self-organizing and require no manual address/route/channel assignments. It is simple to manage thousands or millions of devices resulting in the lowest total cost of ownership.
- Scalability, flexibility and lower costs - Smart Networks are self-organizing and allow true scalability. You can easily add Nodes and Gateways at a very low cost with:
  - No limitation on number of hops
  - No network address configuration
  - No managed hierarchical architecture
  - No hard limitation on number of Nodes per Gateway
- Near real-time network means speed and efficiency – Smart network technology greatly reduces the latency present in other wire line or wireless network solutions. You get the data for on-demand reads, outage notifications, and other applications. In addition, the technology supports automated “over-the-air” upgrades that are self-spreading to increase efficiency and dramatically lower operations costs.
- Robust security - All communications in a smart mesh network are protected by mutual device authentication and derived per-session keys used for high bit rate AES encryption. This hardened security approach allows for authentication as well as confidentiality and integrity protection in each communication exchange between every pair of network devices – Smart meters, Relays, or Wireless Gateways.
- Open Systems and IPv6-compliant network - Networking supports IPv6 standards, which offer expanded IP address space, and simplified management and improved security. Compliance to open systems gives users interoperability, better performance, and more flexibility now and in the future.

## 6. CUSTOMER BENEFITS

Regulated utilities traditionally operate as monopolies with an “obligation to serve” for the benefit of shareholders and customers. Smart AMI Network solutions generate significant financial benefits and have the power to enhance customer satisfaction to new levels.

Multiple demand response and utility operations initiatives can be met with a Smart AMI Network's capabilities to:

- Integrate water, gas and electric meters into one intelligent, bi-directional smart network
- Perform on-demand reads, deliver software downloads, and perform remote testing
- Remotely control and upgrade smart meter firmware to support network connectivity to/from and management of Home Area Networked appliances.
- Broadcast TOU pricing to customers and load management signals to smart appliances through HAN interfaces in support of demand response strategies
- Store selective monthly usage details in smart meters and avoid erroneous trend estimates and inaccurate readings
- Control operations expense by minimizing field calls, truck rolls, and associated expenses
- Use the smart network for distribution automation and distributed generation and control
- Employ open standards protocols to interface with multi-vendor in-home networks
- Support response communications for smart thermostats and load control devices over the Smart AMI Network
- Enable remote connects and disconnects for service order work in transient areas
- Provide customers online access to hourly interval usage and the interactive ability to manage energy related expenses
- Assist in identifying sources of non-technical revenue losses

The most pervasive improvement of a smart meter-based AMI solution is accurate and timely bills, based on interval data. One must also consider the way integrated Smart AMI Network technology can enhance call center operations. With easy access to current and historical data, call center staff will have the data to quickly and easily resolve queries with faster and smarter responses. Another example is timely and pro-active notification of outages, a life saving service for millions of senior citizens in the country. Additionally, secure web-based access to energy data, like that planned by utilities, can educate customers about their energy use and help them make better energy decisions.

## 7. SUMMARY

The most significant benefit of interoperable network solutions is its ability to assist in the delivery of integrated Smart Grid applications like AMI. With AMI technology and customer participation, utilities can use automatic

controls to curtail energy use at peak times, helping reduce customers bills and conserve energy. This process is environmentally friendly, efficient, and reduces the need to build new facilities.

Interoperable Smart Grid systems restore the demand and supply balance while creating efficient energy markets. When it comes to improving resource management, revenue opportunities, and customer service through the use of AMI and Smart Grid strategies, interoperable solutions provide utilities with the capabilities to achieve their goals. Engineered to truly enable interoperable infrastructure that delivers the functions and benefits of the Smart Grid by overcoming complex technological challenges – Smart AMI Networks:

- Equip utilities to more effectively manage their increasing infrastructure demands and growth requirements
- Provide the capacity, controls and self-managing architecture to handle the complex and massive data demands for next generation utility services
- Reduce traditional IT management for faster ROI
- Are proven reliable and fuel new services and support evolving standards for customer service.

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### Biography

Mr. Krishnamurthy is the Vice President for Corporate Development at Eka Systems, a leading provider of communication and networking solutions for the Smart Grid

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# Integrating the Smart Grid: Ensuring You Aren't Outsmarted by the Smart Grid

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## Abstract:

The introduction of the Smart Grid presents new challenges as a result of the wide range of technologies needed to meet the utility's Smart Grid business objectives. For many, the business focus of the Smart Grid includes improving:

- Reliability
- Operational Performance
- Power Quality
- Economics
- Security
- Efficiency
- Safety

The technologies needed to accomplish these objectives cover the range of meter reading technologies, transformer, feeder, fault data collection and analysis, self-healing feeder technologies, loss minimization, distributed generation, voltage control, communications, etc. Clearly, many vendors will be involved.

The classical approach of implementing a technology for a single purpose with a dedicated infrastructure, such as communications, computing platforms, database and software, is no longer practical. Moreover, the automation systems of the pre-Smart Grid era require expensive and unique data maintenance, yet they do not adapt to dynamic changes to the grid's topology affected by manual or program switching; if one technology results in a network change, it alters

the base prerequisite topology and renders other feeder technologies inoperative.

The Smart Grid must overcome these deficiencies. Since all technologies share a common network, a common network model should be employed. Similarly, Smart Grid technologies must be interoperable with existing grid components. The supporting infrastructure of sensors, communications, etc, should be reusable when incrementally adding other technologies.

This paper discusses a distributed implementation of Smart Grid self-healing feeders installed at both PPL Electric Utilities (PPL) and Oklahoma Gas and Electric (OG&E). The implementation uses a dynamic network model which can be used for incremental add-on applications. The solution also shares a common infrastructure of heterogeneous network devices such as relays, switches, reclosers, communications, and protection systems without interference. Furthermore, the lessons learned involve maintaining the network model from a common source for implementation in either a distributed or centralized design, or both.

## 1 Ensuring You Aren't Outsmarted by the Smart Grid

The Smart Grid is expansive in its objectives. A prime example is the breadth of integration and variety of technologies under demonstration as part of the DOE's Office of Electricity Delivery and Energy Reliability (OER) April 2007 announcement regarding the selection of projects to:

“...modernize the nation's electricity grid for research and development activities to improve the security of controls systems for energy delivery and increase the use of distributed generation during peak load periods”.

The DOE objectives behind the selected consortiums demonstrate technology projects aimed at:

- Achieving a fifteen percent reduction of U.S. peak load electricity demand.
- Integration of multiple distributed generation and electric energy storage with price-driven load management.
- Provide Volt-Amps-Reactive (VAR) electric power management.
- Coordinate the Distributed Energy Resource (DER) with existing VAR management and compensation tools.
- Integration of automated metering infrastructure (AMI) into Micro Grid operations.
- Demonstrate “self-healing” networks through the integration of feeder automation technologies.
- Integration of Outage Management System (OMS) into Micro Grid real-time operations.
- Intentionally island customers using automated distribution control in response to system problems.

In addition to the above integration and technology objectives, the assisting objectives include developing information and tools which address the impact of multiple DER technologies, including:

- Control algorithms for autonomous DER operations/automation that address multiple DER interactions and stability issues
- Penetration limits of DER on the substation and feeder
- Coordination and interoperability of multiple DER technologies with multiple applications and customers.

Smart Grid technologies are state-of-the-art; in some cases, they lack maturity, better labeled as

a ‘bleeding edge’ technology. Those utilities who recognize that to rely on legacy technologies is not a practical option, yet acknowledge that the needed technologies are emerging, embrace a program to implement the Smart Grid and label themselves as a “Utility of the Future”.

Often, the first step in the process of implementing one or more these technologies is to evaluate their performance under a “pilot project” prior to their acceptance for general deployment. It is important that any pilot project focuses beyond the mere technical operation to consider all of the other “make or break” criteria that could potentially disqualify it for use or conversely prove it to be acceptable for widespread deployment. To this purpose, the evaluation criteria for any Smart Grid utility should at least consider the question of “scale” and the question of “integration” since these two qualifications alone can become critical keys to the success of the Smart Grid.

### 1.1 A question of scale

*Can the evaluated technology be widely deployed and expanded across the electrical system, while being practically and cost effectively maintainable?*

Often the cost of maintenance is not evaluated or considered within the scope of the pilot project. Smart Grid technologies require a combination of a capacious database, complex modeling, convoluted scripting or considerable mapping to perform its function. In a “pilot program”, the labor to build and maintain the core data is overlooked or underestimated in an effort to prove the operational sufficiency of the technology.

Likewise, the Smart Grid technology requires a supporting infrastructure. Sensors collect the data, communications transmit the data, and processing units assess the data. Is this investment in the infrastructure dedicated to a single technology or is it shared by all?

For any single technology, the utility must understand the cost of the engineering and maintenance effort as well as the supporting infrastructure’s capital cost; if the cost is extrapolated across the entire system under a wide scale deployment, would the resultant cost be considered justifiable?

## 1.2 A question of integration

*Can the evaluated technology integrate with other feeder automation technologies without negatively impacting the performance of the other? Will they share all common and critical infrastructure?*

Pilot projects usually evaluate each Smart Grid technology in isolation. In doing so, the pilot projects often fail to replicate the actual network conditions of the Smart Grid where more than one Smart Grid application or technology is making independent changes to the grid. The problem occurs where network changes made by one technology renders another invalid. For example, the greater majority of the self-healing feeder technology in use today utilizes a solution which depends upon the assumption that the initial feeder configuration is in its “normal” state. This is a poor assumption to make. If another technology (such as emergency load transfer, or automated switching to restore an unfaulted section back to service) renders the resultant feeder topology in a non-standard or “abnormal” state, this resultant “abnormal” condition should not render other solutions impotent. The Smart Grid technologies should cooperate, not cancel, one another.

In practice, utilities employ devices of many types from many manufacturers. Smart Grid technologies (such as feeder automation) must operate with existing sensors, switching and protective devices. Solutions that cannot embrace a heterogeneous environment of devices are not true Smart Grid technologies. The question is can these technologies be effectively integrated?

Combining the issues of scale with integration is critical. Once the cost of the new technology is understood, and assuming that a suite of automation and optimization technologies can be integrated with others, the next question is: what is the incremental infrastructure cost to deploy other technologies on the same network? This question is important to the overall success of the Smart Grid. For some utilities, the installed cost and infrastructure cost, as well as the cost of ongoing resources, training and maintenance to implement any single technology, may be prohibitive or impractical. Certainly it will involve organizational commitment and changes. One

major southern California utility concluded that the “[AMI] business case analysis shows that operational benefits from AMI alone do not justify full or partial deployment of AMI.” Yet avoiding the Smart Grid is not an option for the Utility of the Future. One common approach is to back into a justification by relying heavily on soft benefits.

But there is another answer. If the Smart Grid is approached from an integrated view point, as it should be, the infrastructure cost is borne largely by the first technology installation, while the incremental cost of each technology thereafter is minimal. So an integrated approach to the Smart Grid increases the payback benefits while lowering the incremental installation cost.

Therefore, any deployment of the Smart Grid must develop a strategy of information integration and demonstration of maintenance, while focusing on security. This is best achieved by breaking the Smart Grid system architecture down into common components that are built on standards. Yet there are two problems with standards: it has been said that the one thing about standards is that there are so many of them; and the standards that are needed are not yet mature. The Smart Grid must take a practical approach wherever possible.

## 2 Common Components

Individually, each technology can be engineered to meet its operational objectives. However, due to the wide range of co-existent technologies required to meet the various Smart Grid objectives, there are common components that each technology shares. Since the cost of deployment plus the on-going cost of daily maintenance may be prohibitive, it is imperative for successful deployment of the Smart Grid to find and share common components within the infrastructure.

Common components may be categorized in different ways. For example, practical deployment of substation and feeder automation solutions includes:

1. Data Sensors
2. Data Model
3. Communications

## 2.1 Data Sensors

The number of data sensors will dramatically increase in Smart Grid implementations. Previously (and currently for many), most distribution system data has been collected within the substation fence, never venturing past the feeder circuit breaker. For the first time in most utilities, data will be collected from sensors located beyond the distribution substation fence, from the feeder switching device, from current or fault indicators, from the feeder load transformer and from the load itself.

Each Smart Grid technology requires specific data in order to accomplish its function. Where the data is not already available, sensors are installed to collect the needed data for that technology. Too often in the past, utilities have installed a single application, such as a self-healing circuit, which makes use of private data collected by dedicated or specific sensors while using communications that cannot be shared. A true Smart Grid application, however, will collect and share the data with other applications, such that what one technology collects, another technology may make valuable use thereof.

The number of data objects in many of the IED devices range from hundreds to over one thousand objects. The time to configure each device is typically excessive, especially when considering the large number of devices involved. It is necessary that the IED devices and sensors to be integrated include a pre-defined profile within the supported protocol. For example, the modern standard protocols, such as DNP 3.0, IEC 61870 and IEC 61850, support explicit descriptions to uniquely identify each data object within an IED. This is accomplished within a standard definition in order to pre-define the objects needed for Smart Grid applications (such as feeder automation). Since a single IED may describe a thousand data objects, new versions of these standard protocols define that the object profile description will be provided as an electronic (i.e. xml) file in order to speed up the configuration process. These standards seek to ensure simplification in the pre-definition for the profile support and to minimize the configuration time.

It is important going forward that standards are selected and manufacturers are required to meet certification requirements for interoperability. However, standards will not solve all of the problems, since the standards are continually evolving. Even though data objects are uniformly defined by name and function between IEDs, each IED device behaves differently within a standard, even within a standard as advanced as the IEC 61850. For example, IEC 61850 presents for similar IEDs, different data from different manufacturers. In order to uniformly define a data attribute by name and function across all IEDs, IEC 61850 supplies a range of attributes, such as the IED's object data-set and descriptive attributes, but it does not dictate that the attribute shall exist; the standard does not impose functionality between similar IEDs from different manufacturers.

DNP 3.0, which is one of the most widely available and successful standard protocols in use, varies significantly enough for each IED manufacturer that the presentation of data is not uniquely selective upon access, and object types vary from device to device.

While it is important to select and support a standard such as DNP 3.0, IEC 870 or IEC 61850, the Smart Grid integrator must never-the-less be prepared to manipulate the data retrieved from the IED. This is necessary in order to normalize the data from all of the IEDs, since there is no standard imposing that any particular attribute shall be provided. It is still necessary for the integrator to customize the handling of the specific IED.

For example, within the controller it is necessary to perform the following to overcome the lack of an object class definition agreement between IEDs:

- Many IEDs detect an over-current condition, but not all in the same manner. Therefore, it is necessary to apply a Boolean calculation to compose the fault indication.
- IEDs reset the fault indication in a different manner. Self-healing feeder automation requires that the reset of the fault indication is performed shortly following a fault state to a normal state; otherwise it may be reinter-

preted as a new fault condition. An accurately reported upstream fault would be misinterpreted as being located further downstream. It is necessary that the automation application itself resets the IED flags as needed.

- In order to ensure that a false restoration condition isn't initiated, an auto recloser lock out state must be combined with a fault indication. Furthermore, the fault indication must be persistent for a minimum time period, to account for the slow IED reporting time for the various IEDs.
- The self healing feeder automation application must check other data and indications which are not part of the IEDs database, such as local/remote indication or switches.
- In order to calculate the load profile for switching plan analysis to prevent overloads, the P/Q per phase must be determined. Some IEDs do not provide this information. Some will offer the total load for all phases or the voltage, current magnitudes with phase angles. It is necessary that the integrator calculate the P/Q per phase for the IED devices that do not provide these values.
- Validity checks of various critical software processes must be performed to ensure all applications and subsystems are operating correctly in order to ensure a quality solution. These flags and processes are individually collected and monitored

The Smart Grid data front end must accomplish this manipulation independent of the application and insert the result into the network database and model.

## 2.2 Data Model

The single largest cost and the most critical effort in support of integrated Smart Grid applications and technologies are the completeness and real-time accuracy of a network database/model. Private implementations of the database dedicated to specific applications are not practical from a cost effective or a accuracy viewpoint. In order to minimize costs and maximize accuracy, a common database and model is required for all integrated Smart Grid applications. The collec-

tion of network relevant binary and analog data from the various sources, sensors, IEDs and calculations such as P/Q, fault conditions, alarms and topology network state analysis should be stored in a common repository where all applications have access to this data. In this way, all applications will share the most important and common resource in the Smart Grid—its database.

The creation and subsequent daily maintenance of the “operational database/model” (OpDM) is converted and maintained from a single common “maintenance database/model” (MaintDM) source—typically the GIS. However, the OpDM is the real-time source for all operational data. In other words, there are two sources: the maintenance source and the operational source. For the purpose of this discussion, we will focus on the OpDM operational source.

The operational source database/model may be geographically distributed (e.g., at the substation) and/or centralized (e.g., at the control center). The OpDM functions and is updated as a single virtual database/model which services all of the applications that require access to the network OpDM. If the Smart Grid applications are “model-driven” rather than “script-driven”, and are deriving their switching solutions and analysis from the real-time OpDM, the problem with assuming a “normal” topology as a starting point in a single application environment is eliminated. An integrated environment of Smart Grid applications can successfully co-exist deriving their solutions from a common OpDM and will not interfere with one another's solutions. They will become adaptive to the current network state.

The size of the DMS database will become very large indeed. Not only are switches, transformers, etc., as represented in existing transmission system models, each fuse, customer load transformer, line section etc is represented in a DMS feeder model. Even without the customer objects which are usually included in a OMS model, the size of the DMS model for a medium size utility can range from 500K objects to well over one million objects. Our experience has been that medium to large utilities can expect the count of

objects to triple that number. This leads to three important conclusions:

1. The daily process of converting and maintaining the model from the Main DM source must be automatic, fast and powerful.
2. Since the model is closely coupled with the distribution map display, the display itself must be automatically created and maintained concurrently with the OpDM, without manual manipulation.
3. The OpDM is best implemented as an object-oriented model where assets (physical objects) are associated by equipment that can be represented on a map. A change to a single asset must be inherited by all instances of the asset.

Since concurrent Smart Grid applications will now become integrated, it becomes necessary for the utility to adopt a standard that allows openness and interoperability in an environment of third-party Smart Grid applications. However, to avoid custom data transformations when integrating third-party applications, such as the transformations described above when integrating Smart Grid sensors, a common standard OpDM is needed. The most important DMS standard necessary to support this interoperability is the IEC TC57 WG14 extended IEC61968 common information model (CIM). The CIM is defined using a Unified Modeling Language (UML) for system specification, visualization and documentation. Since the IEC61968 standard does not dictate the database schema or even reside in a database, existing databases, regardless of their schema, do not need to change. The standard defines the data, their relationships and API or generic interface which may be implemented in a wrapper for legacy databases.

The relevant "standards" organizations that offer guidelines and encourage and define standards development, promoting interoperation consistent with the principles and framework in use and evolving today include: the GridWise Architecture Interoperability Framework, EPRI's IntelliGrid reference design, IEC Common information model (CIM) and other industry interoperability

standards applicable for Micro Grid operations.

### 3 Communications

Smart Grid communications must support a re-useable infrastructure. Many existing Smart Grid implementations deploy a communications system that is dedicated to a particular technology implementation. This was perhaps practical in a single application environment. However, due to the requirement for heavy integration of Smart Grid applications and technologies plus the expected massive increase in data sensors, a communication infrastructure which can support the data traffic and which can be shared by all is critical for success.

Not all of the data collected by each IED or sensor is destined for the same application, enterprise database or processor. If the data from an IED cannot be configured to supply only user-selected values, or if it cannot segment its data for different destination processors, it will impose a severe bottleneck on the communication system and the destination processors. It is necessary to create a hierarchical communication structure which can take advantage of the natural Smart Grid architecture.

It has been our experience that most existing IEDs, such as reclosers, do not have a configurable method of retrieving individual data points. Rather, they are reported in blocks of 100s of points where only one point in the block may be required. The IED/sensor data must first be collected, then filtered to reduce the data volume in order to report only the data that is necessary to the client. Typically a RTU or controller is used to collect and filter the data.

Often it is important to perform needed calculations at the point of measurement in order to reduce the volume of data to be transmitted, as well as to reduce the calculation

load on the destination processor. For example, where P/Q is not collected by the IED at a point of measurement on the feeder, the preferred method is to perform the calculation at the point of collection rather than to send the raw values (such as the angle, current and voltage per phase) in order to calculate the PQ at the client processor. Another example is the fault indication flags derived from current/time curves, since the data traffic is reduced to a single status bit rather than transmitting the analog components.

IED data should be further segmented into data classes such as real-time data and near real-time data. Real-time data can be categorized into scan groups appropriate for the time constraints of the real-time application. This technique reduces the communications requirements and improves system performance. Data concentrators are effective in collecting the data, performing calculations, partitioning the data and passing it on to the OpDM client in the network.

Many enterprise communication specifications will no longer allow serial modem communications between the field and the centralized application client. UDP is often no longer acceptable. Utilities are designing communications architectures which make use of listener sockets, or smart sockets and TCP/IP networks to enable sensors and concentrators to publish or request the data. Applications clients or the OpDM will then subscribe to the specific data it wishes to retrieve. However, as each IED now conceivably has an IP address with the ability of dumping a massive amount of data within the network, it is important where necessary to make use of RTUs / data concentrators in order to reduce the bottleneck.

Due to the massive IED data volume, a modern distribution substation RTU/concentrator database is able to sup-

port 100,000 points. Control Center to substation network configurations must support architecture variations which include configurations as single session, single IP with dedicated ports per session to configurations with separate IP addresses per session for each data type; in particular, data types are defined in the RTU/concentrator to segregate power market data from operational data.

Meeting NERC Critical Infrastructure Protection security includes the normal personnel security features in control centers as well as architectural safeguards. However, this technology is now appearing in field locations as firewall protection is used at the plant or substation site. In highly sensitive operations, all TCP connections to RTUs should be initiated from the CC to listener sockets on the RTU on a defined port. In other words, unsolicited events will be considered as a security risk by many utilities. IP-based communication protocols at pole top devices also include encryption with IP matching for security. All communication data endpoints will need to be secure to prevent any form of malicious injection attacks. This is especially going to be a challenge when data convergence and virtualization platforms are prevalent in the utility landscape.

Reliability is improved as the pole top RTUs begin to operate in a meshed network communication system. The meshed communication network uses automatic routing as it searches for the strongest signal path in the event of a loss of communications.

Practically, the communication infrastructure must support an advanced industry standard master and IED protocol. Legacy proprietary protocols must also be supported until the devices can be replaced to support the new standards. These legacy protocols

are best supported using the RTU/concentrator. Advanced protocols will support the communication system described above while it pre-defines the data objects that can be supported for interoperability. In order to achieve interoperability even while using standard protocols, the minimum set of data objects to be used should be specified by the user, and the RTU/concentrator should be able to parse the protocol client requests as defined by the protocol's object definition.

Although the IEDs and sensors may not support these requirements, use of RTUs and concentrators in the architecture can and will still achieve the objective while improving performance.

#### **4 Summary**

The Smart Grid is not around the corner, it cannot be avoided—the Smart Grid is the burning business objective of every major utility. Yet the Smart Grid means different things to each utility. The phases of implementation, the mix of technologies and the degree of integration will be determined largely by the business cases that each utility can justify. Since cost benefit justification is fundamental, a smart approach to the Smart Grid is necessary where common components are shared and the technologies are integrated. It has been shown that an integrated environment of Smart Grid applications can successfully co-exist and yield the cost benefit advantages necessary for justification.

As the Smart Grid matures, industry standards will lead the maturing process. However, as we advance, the standards on hand combined with the integration technology used “to fill in the cracks” and the plan of deployment, will determine the ultimate financial success of any Smart Grid implementation.

#### **5 Biography**

Mr. Ockwell holds a B. S., EE Degree, University of Saskatchewan, Saskatoon, Saskatchewan, Canada. Mr. Ockwell joined Advanced Control Systems in 1995 and is the Technology Officer.

# Linking Continuous Energy Management and Open Automated Demand Response

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**Keywords:** Continuous Energy Management, Automated Demand Response, Energy Efficiency, Demand Side Management, Electricity Value Chain

## Abstract

Advances in communications and control technology, the strengthening of the Internet, and the growing appreciation of the urgency to reduce demand side energy use are motivating the development of improvements in both energy efficiency and demand response (DR) systems. This paper provides a framework linking continuous energy management and continuous communications for automated demand response (Auto-DR) in various times scales. We provide a set of concepts for monitoring and controls linked to standards and procedures such as Open Automation Demand Response Communication Standards (Open Auto-DR or OpenADR). Basic building energy science and control issues in this approach begin with key building components, systems, end-uses and whole building energy performance metrics. The paper presents a framework about when energy is used, levels of services by energy using systems, granularity of control, and speed of telemetry. DR, when defined as a discrete event, requires a different set of building service levels than daily operations. We provide examples of lessons from DR case studies and links to energy efficiency.

## 1. INTRODUCTION

The objective of this paper is to explore a conceptual framework and a set of definitions that link building energy efficiency, control system features, and daily operations to electric grid management and DR. DR can be defined as mechanism to manage the electric demand from customers in response to supply conditions, such as through prices or reliability signals. We discuss how these relate to the GridWise® interoperability context [1]. Such concepts and definitions are needed as the building industry and the electric utility industry become more integrated in supply demand side operations. It is critical for the energy industry to more strongly link demand-side performance objectives with electricity supply-side concepts.

One motivation for this framework is to facilitate understanding of automation of DR in demand side systems. The examples in this paper draw from research on

commercial buildings, though the concepts are relevant to industrial facilities and residential buildings. This framework also emphasizes existing buildings but the ideas are applicable to new buildings and may help guide concepts to move DR into building codes and standards.

A key theme of this work is to understand not just how much energy a building uses, but when it uses energy and how quickly it can modify energy demand. This is not a new concept, but as more sophisticated controls are installed in buildings, the opportunities to better link demand and supply side systems are improving. Previous papers have discussed definitions of energy efficiency, daily peak load management, and DR [2 & 3]. This paper discusses the different speeds of DR, automation basics, and related control system features and telemetry requirements.

One objective of this DR research is to evaluate building electric load management concepts and faster scale dynamic DR using open automation systems. Such systems have been developed by the California Energy Commission's Public Interest Energy Research Program (PIER). The PIER Demand Response Research Center (DRRC) has led this effort and developed and deployed systems throughout California and the Northwest in a technology infrastructure known as OpenADR [4]. The intention of the signaling infrastructure is to allow building and industrial control systems to be pre-programmed, enabling a DR event to be fully automated with no human in the loop. The standard is a flexible infrastructure design to facilitate common information exchange between utility or Independent Systems Operator (ISO), and end-use customer. The concept of an open standard is intended to allow anyone to implement the signaling systems, providing the automation server or the automation clients. These standardized communication systems are being designed to be compatible with existing open building automation and control networking protocols to facilitate integration of utility/ISO information systems and customer electrical loads [5].

The next section of this paper outlines the six key elements of the conceptual framework for traditional energy management and emerging demand responsiveness. This is followed by a section that discusses levels of building services in relation to the six key elements. This section also discusses control systems and the speed of telemetry.

Next we present an example of how this framework can be applied to advanced lighting controls and we reference the New York Times Building in New York as an example of an as-built advanced multi-functional lighting control system. We conclude with a brief summary and key research issues associated with the framework.

## 2. LINKING ENERGY EFFICIENCY AND DEMAND RESPONSE

We provide a brief description of six energy and demand management concepts. The first three concepts we classify as “traditional” energy management. The second three concepts are “emerging” demand responsiveness. Following each of the six concepts is a comment on the role of automation and timescales. These six sections are:

- **Traditional Energy Management**
  - Continuous energy minimization
  - Monthly peak demand management
  - Daily time-of-use energy management
- **Emerging Demand Responsiveness**
  - Day-Ahead demand response (Slow DR)
  - Day-of demand response
  - Ancillary services demand response (Fast DR)

### 2.1. Traditional Energy Management

#### 2.1.1. Continuous Energy Efficiency

Energy efficiency can be defined as providing some given level of building services, such as cooling or lighting, while minimizing energy use. A strategy or technology that provides the same amount of service with less energy is a more efficient technique. A good example is to compare the lumens per watt of a fluorescent versus incandescent light. At the whole building level a more efficient building is one that provides HVAC, lighting, and miscellaneous plug load services using less energy for the same services than a comparison building. To actually achieve high levels of energy efficiency in a complex commercial building requires energy efficient components combined with well commissioned controls and good operational practices.

The key point about energy efficiency is that building control strategies and operations should be optimized with energy use minimized every hour of the year for the given “service” the building is providing at any moment. Our success in reducing energy use in commercial buildings is strongly linked to our improved ability to measure the services the buildings systems provide while ensuring that energy waste is reduced as much as possible. We need to

reduce heating, cooling, ventilating and lighting of spaces that are unoccupied.

**Automation** – The automation of continuous energy management is provided by energy management and control systems (EMCS).

**Timescale** – Thousands of hours per year

#### 2.1.2. Monthly Peak Electric Demand Management

The majority of large commercial buildings in the US pay peak electric demand charges. These charges often represent about one-third of the monthly electricity costs, yet they are not as well understood or as well managed as total (monthly or annual) electricity use. Peak electric demand charges typically have a time period they are associated with, such as the afternoon from noon to 6 pm. Some tariff designs have peak demand charges that apply to the monthly peak during on, partial or mid-peak, and off peak periods. Others have demand ratchets that may result in a peak demand that occurs in one month to set charges for 12 months. The key issue here is it is not how much energy is used, but when the most demand for electricity occurs. Efforts to reduce these charges require understanding rates, building controls, weather sensitivity and occupancy patterns.

**Automation** - Historically many energy management systems have offered demand-limiting features to reduce the peak demand by “limiting” electricity use when demand is high. While these are in limited use, they are available in many EMCS platforms and they require integrating whole-building electric use data with the EMCS.

**Timescale** – A few hours per month

#### 2.1.3. Daily Time-of-Use Management

Similar to the presence of peak electric demand charges, most large commercial buildings have time-of-use (TOU) charges where electricity during the day time hours is more expensive than nighttime use. TOU energy management techniques involve careful consideration of scheduling equipment to reduce use of expensive electricity if possible.

**Automation** – Most EMCS provide scheduling of HVAC and lighting systems including programming of demand shifting strategies. As mentioned below most buildings do not use thermal storage so they do not “charge” energy systems during off peak periods. Some facilities do, however, modify energy use patterns to reduce expensive on-peak energy.

**Timescale** – Key periods of the day

The above three basic concepts are applicable to most commercial buildings with TOU and peak demand charges.

We have not, however, described more advanced strategies such as thermal storage or pre-cooling that allow for variations in charging and discharging of thermal systems. To optimize building performance we will want to consider what we are trying to minimize. Optimal control strategies to minimize energy costs may differ from strategies to minimize total energy use or CO2 emissions (as CO2/kWh may vary between the day and night). Ideally one can achieve both low energy use and low energy costs!

## 2.2. Emerging Demand Response Management

As we move toward a future in which the electric grid has greater communication with demand-side systems, it is useful to define and explore the time-scales of energy management and DR.

### 2.2.1. Day-ahead (“Slow” DR)

Day-ahead DR involves informing a demand-side customer the day before a DR event that the DR is pending the following day. In the case of manual DR this notification allows the facility manager to prepare a facility to participate in DR for the given schedule. Day-ahead real-time pricing can be an example of Day-ahead DR. Some RTP designs issue 24 electricity prices for each hour of the following day. This allows facility managers to schedule their loads and manage their electricity costs.<sup>1</sup>

**Automation** – Most DR in US commercial buildings is manually initiated. However efforts to develop and deploy open DR automation standards have shown that most buildings with EMCS are good candidates for DR automation. Day-ahead signals allow the EMCS to schedule next-day DR events and are sometimes used to automate pre-cooling [6]. The DR program evaluations in California showed that about 15% of the time the person responsible for the manual response did not act [7].

**Timescale** – 50-100 hrs/yr (though day-ahead hourly real-time prices can be continuous, high price events are fewer hours per year.)

### 2.2.2. Day-of DR

Day-of DR can be defined as DR events that occur during the day when the event is called. These DR events typically have a scheduled time and duration. Day-of DR may also be an hour-ahead or 15-minute ahead real time price. A facility manager has less notice to prepare to participate in such events.

**Automation** – Similar to Day-Ahead DR, Day-of DR is often initiated manually. The more “real time” the DR, the more compelling is the need to automate DR because the notification for a person in the loop is more problematic

with faster time scales of DR. Pre-cooling may not be possible in “Day-of” DR events.

**Timescale** – 30-60 hrs/yr (though hour-ahead real-time prices can be continuous, high price events are fewer hours per year.)

### 2.2.3. Fast DR

A third class of DR is ancillary services. There are several classes of ancillary services such as load following systems, spinning and non-spinning reserves, and regulation capability [8]. Fast DR can be thought of DR that is available quickly and the DR may not last long but it can be harvested quickly. The DR event may only be five minutes in duration. There are several recent research projects that have explored such “fast” DR [8].

**Automation** – Fast DR requires automation because people often cannot “jump” to action when notified of a fast DR event. These fast DR events may not last long. The electric loads are often restored within five to ten minutes of when they were curtailed [8]. The existing Internet-based DR automation systems are being considered for their speed and applicability to this class of DR.

**Timescale** – 5-10 hrs/yr

## 3. SERVICE LEVELS, CONTROLS AND TELEMETRY

There are three key features of demand-side systems to consider as commercial buildings begin to participate in all six of the electricity value chains listed above. These are, Levels of Service, Granularity of Controls, and Speed of Telemetry.

### 3.1. Levels of Service

There is a tremendous opportunity to better link DR and energy efficiency by improving understanding of the levels of service provided by existing buildings and building end-use systems. Take the example of an office building which is designed to provide ventilation to support good indoor air quality, indoor climate control, lighting, and other services such as hot water, office equipment plug loads, and vertical transport (elevators). Good energy management practices assume that there is not much energy wasted. The building is heated, ventilated, lit, and cooled at optimal levels to provide comfort, but energy waste is minimized.

Given this as the baseline, to participate in DR requires that the service level that is provided in normal operations is minimized. Common examples are to change temperature set points or reduce lighting levels. Better measurement and monitoring of actual temperatures and lighting level distributions will improve our ability to change service

<sup>1</sup> In California “Day-ahead” DR has been referred to as price

levels since we want to ensure “optimal energy efficiency” as the starting point for DR.

### 3.2. Granularity of Advanced Controls

Similar to the desired ability to “measure” levels of services provided in a building is the desire to “control” the level of service. To participate in DR events we do not want to simply “turn off” a service, rather we’d like to “reduce” the service. This ability to improve control can provide features important for continuous energy management, monthly peak demand management, and daily TOU control. Further examples are provided below.

### 3.3. Speed of Telemetry and Response

This final category of infrastructure moves us from manual DR to fully automated systems. Research and automated DR programs in California have shown that existing Internet systems are fast enough to provide a signaling infrastructure for Day-ahead and Day-of DR [9]. Research is beginning to explore the capabilities of such systems for fast DR.

Table 1 below summarizes the key concepts explored in this framework

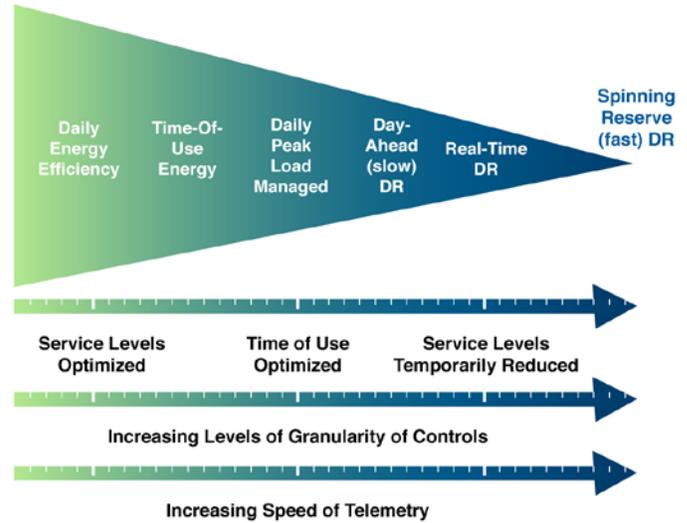
**Table 1: Summary of demand-side systems features to electricity value chains**

Concept	Automation	Time Scale	Level of Service	Speed
<b>Continuous Energy Management</b>	Provided by EMCS	1000s hrs/yr	Optimize each hr	Slow
<b>Daily TOU Energy Management</b>	Provided by EMCS	Select time of the day	Optimize for TOU	Slow
<b>Monthly Peak Demand Management</b>	Provided by EMCS	Few hours/mo	Minimize demand charges	Slow
<b>Day-ahead DR</b>	Can be automated	50-100 hrs/Yr	Temp reduced	Medium
<b>Day-of DR</b>	Can be automated	30-60 hrs/Yr	Temp reduced	Medium-Fast
<b>Ancillary Services</b>	Requires automation	5-10 hrs/yr	Temp reduced	Fast

## 4. LINKS TO GRIDWISE

The GridWise® interoperability framework [1] was developed to facilitate integration and information exchange among participants. The integration of technologies to link energy efficiency and OpenADR must meet the requirements of the electricity value chains and key features of demand-side systems, namely levels of service, granularity of controls, and speed of telemetry. These technology requirements vary based on the type and use of energy management. For example, the EMCS and technologies used for continuous and TOU energy

management and peak demand management can be well integrated and interoperate with the needs of OpenADR. Subsequently, the same OpenADR system infrastructure could be integrated and enhanced to meet the requirements of ancillary services. This essentially means that the underlying technology should be designed to meet the context-setting framework of varied demand-side requirements. The figure below (Figure 1) show linkages between the electricity value chains and their key features those are necessary for a robust technology framework.



**Figure 1: Service levels, controls, and telemetry in electricity value chain**

The left side of the figure above (Figure 1) is meant to show that most hours of the year we are concerned with continuous energy efficiency. Each hour energy use can be optimized relative to the energy services begin delivered. As we move to the right, few hours of the year are included and we begin to reduce building service levels in DR periods.

The second bar in the figure above (Figure 1) adds a level of describing control system granularity. Our ability to provide fine grain controls into end-use building systems improves both energy management and demand responsiveness. Further examples are provided below using dimming lighting and DR capabilities.

The final bar in the figure adds a third layer to describe telemetry. As we move to the left toward faster DR systems, increasing speeds of telemetry are needed to initiate the DR. While this paper does not go into the details of all of the functional requirements of such systems, we acknowledge that the end-use controls within the building become a key component of the end-to-end system for DR.

The use of Internet-based signals and IT with a Service Oriented Architecture (SOA) using web services and well-designed IT systems for DR can meet the demand-side systems' needs in relation to the electricity value chain. SOA, which uses eXtensible Markup Language (XML), a widely accepted standard for communication, and an Internet-based platform, can facilitate communications interoperability and ease of sharing structured data among complex systems. Such interoperability needs are in use by the Building Automation and Controls Network (BACnet) protocol in form of BACnet web services (BWS) [10]. Thus, the OpenADR standards that delivers both price and reliability signals, are an important step toward integration and automation of DR. The context-setting framework defined by GridWise to meet technical, informational, and organizational requirements for interoperability within DR systems is well studied and developed for OpenADR and is being commercialized throughout California. While OpenADR primarily facilitates technical and informational needs among DR systems (both Human to Machine and Machine to Machine), the information model also considers facility or end-user's needs when signals and data pertaining to DR events are sent and the facility determines the optimal DR strategy based on that information. OpenADR is also being evaluated for ancillary services in new research efforts on Fast DR.

### 5. ADVANCED LIGHTING SYSTEM EXAMPLES

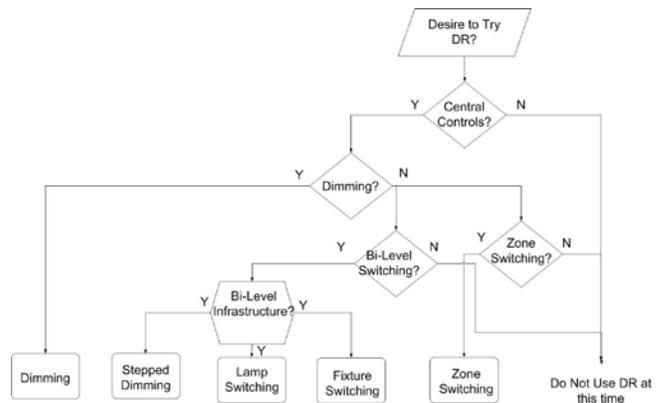
Today's dimming lighting systems are perhaps the best example of an advanced emerging technology that provides daily continuous energy minimization with excellent DR capability. By drawing less when there is abundance of daylight or reducing electricity from the grid when electricity costs are highest, dimming ballasts are an enabling technology that allows building lighting loads to become more elastic. Concerns for electricity disruptions and power outages have stimulated the industry to re-examine and re-design dimming controls to implement DR and energy efficiency measures. Advances in lighting technologies coupled with the pervasiveness of the Internet and wireless technologies have led to new opportunities to realize significant energy saving and reliable demand reduction using intelligent controls [11].

Many manufacturers now produce electronic lighting control equipment that are wirelessly accessible and can control dimmable or multilevel lighting systems while complying with existing and emerging communications protocols. These controllers are well-suited to retrofit applications where it may be less cost-effective to add wiring to communicate with downstream lights. The lighting industry has also developed new technology with improved performance of dimming lighting systems. The system efficacy of today's dimming ballasts compare well

with non-dimming ballasts, where historically there was an energy penalty for dimming.

As a result, from an energy efficiency perspective, dimming ballasts can provide seamless integration of indoor lighting and daylighting delivering continuous low energy use with optimized lighting levels. From a DR strategies perspective, dimmable ballasts can be utilized for demand limiting and demand shedding. Often times, even when dimming strategies are detectable, they can still be acceptable by the occupants [12]. In the newly built New York Times building, the installation of individually addressable dimming ballasts provides highly flexible lighting systems which can minimize energy use for lighting when there is adequate daylight. Advances in lighting control algorithms also facilitated demand shedding of lighting loads to allow good participation in regional DR programs [4].

The process to develop an automated DR strategy based on which lighting control features and layout one has in their building is summarized in figure 4 below. A building operator can use either a manual or automated approach. If central control of lighting is available, the next step is to evaluate the "granularity" of the lighting control which is determined through a set of yes/no questions. Advanced lighting controls and increased levels of granularity allow us to define explicit steps in building lighting that can potentially be exercised during DR events.



**Figure 2: DR decision tree for lighting strategies**

Research is also beginning to explore the possible role of dimmable lighting for regulation capacity. Regulation capacity is generation that is on-line, and synchronized with the ISO so that the energy generated can be increased or decreased instantly through automatic generation control (AGC). While there are many technical challenges this research will address, the main objective is to explore whether the reserve markets may be better served if the ISO can obtain small load reductions from many distributed loads, rather than megawatts of power from a few generators.

## 6. DISCUSSION AND RESEARCH NEEDS

As we begin to explore the functional requirements for linking buildings to the electric grid we must ensure that we understand the fundamental concepts to support optimal and continuously monitored energy efficiency. Many of the technologies required for DR can benefit energy efficiency and advances in controls and service level monitoring will provide greater flexibility in energy management. As energy markets become more complex and there is a growing urgency for greater levels of energy efficiency, facility managers will need to explore better control of demand-side systems.

Facility engineers will need tools and systems to understand their existing systems and how it can participate in these new DR markets. Many energy markets will see dynamic prices and DR programs that provide economics incentives for facilities that can modify their end-use loads.

As we enhance our experience and understanding with the dynamic energy management concepts described above, our next technical challenge will be to quantify the performance metrics associated with each of the domains. For example, whole-building energy benchmarking is widely practiced and well understood process. Whole-building peak demand benchmarking is not! Electric load factors that compare average energy use and peak demand help characterize how “peaky” a building load shape is. Such load factors could be developed for different times of the day. Beyond the whole-building benchmarks are the opportunities to move into end-use benchmarks. Lighting system benchmarks are likely to be more straightforward than HVAC because of the lack of climate sensitivity.

## 7. SUMMARY

This paper has described a framework for characterizing energy use and the timescales of energy management for both energy efficiency and DR. This work builds on our experience using a standard set of Internet signals to trigger DR events in buildings. The development of advanced controls for energy management has also helped improve the ability of commercial building loads to be good DR resources. Further work is needed to develop tools and methods to help building owners and facility managers evaluate investments in advanced controls for both energy efficiency and DR.

## 8. ACKNOWLEDGEMENTS

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### **Biography**

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# "Going the Distance to Connect Consumers to the Smart Grid: The New Frontier for Energy Efficiency and Interoperability"

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Tendril

**Keywords:** Smart Grid, Energy Efficiency, Interoperability, Residential Energy Management

## Abstract

Advances in metering communications and in-home technology have created opportunities for utilities and their residential customers to enter into a genuine dialogue about managing energy – whether that’s to shift load from one (higher priced) time to another (lower priced) time, lower total electricity costs, improve grid reliability, enable distributed energy transactions or lessen environmental impact. The new wave of Residential Energy Management Systems (REMS) are giving consumers real-time information and simple tools to help them manage their consumption in conjunction with utilities.

REMS and open standards will play a critical role in creating a smarter, interoperable and collaborative grid. This smart grid can respond flexibly to changes in demand and price and will contribute to a cohesive and interactive system that is easy to use for all consumers and energy providers.

## I. Challenges Facing the Residential Energy Market

The electric power industry today, aside from the advent of the one-way AMR drive-by meter solution, is still largely an electro-mechanical dominated industry that has been built to optimize ubiquity of service, reliability and economic fairness. These optimizations had little

need for more advanced digital and networking technologies until recently – when society at large decided otherwise: a need to be efficient with overall consumption and further promote environmentally sound solutions.

The industry, especially the residential-focused portion of it, faces a number of challenges today that exacerbate the old electro-mechanical infrastructure:

1. **Demand is increasing** as consumers continue to buy larger appliances and ever-greater number of electronics and other digital devices. Demand isn’t just increasing in the developed nations either; it is also on the rise at an even more dramatic rate in some of the developing nations as well. With the dawn of Plug-in Hybrid Vehicles (PHEVs) rapidly approaching, this presents yet another pressure point that the current grid is ill-equipped to handle.
2. **Supply is constrained** as utilities face rising commodity costs, increased regulatory hurdles (specifically around grid reliability, environmental and energy efficiency concerns) and consumer resistance to building new power plants. Some US states are so grid-constrained that they forecast rolling black-outs or rolling brown-outs as early as summer 2009 and, hence, have regulatory mandates to reduce overall electricity consumption to avoid loss of service. Other states have more than ample carbon-fuel based electricity

generation and have said “thanks, but no thanks” to any more. Almost all have mandated both renewable energy targets *and* energy efficiency targets to their largest electric power providers.

3. **Consumer awareness** of the rising cost of energy consumption (via the price underlying commodities) and the impact of carbon-producing fuels on the environment is growing. According to Sir. Nicholas Stern, the UK expert advisor to Tony Blair on Global Warming, every person in the United States will have to cut their carbon emissions by 90% by the year 2050 in order to forestall a five-degree Centigrade rise in worldwide global temperatures – a swing not seen since the Ice Age. On the commodity side of the equation, several US states are seeing increases of as much as 40% of their base electricity rate(s) in 2008 due to increases in commodity prices.
4. **Consumer comfort** with a decade’s worth of digital and network technology training which has made a vast majority of residences technically literate about basic digital technologies with a concomitant demand for real-time information flow. Consumers expect information at their fingertips. They routinely have in-depth, disaggregated information about their telephony use, their gas mileage and their financial transactions. “Why,” as most ask, “can we not have information about the single biggest consumer of electricity we own – our homes – on a more than monthly basis?”
5. **Distributed generation** is coming in the form of cheaper solar and geo-thermal options for consumers and the PHEVs that not only consume electricity but store it as well. The Chevy Volt and the Tesla are just the tip of the iceberg when it comes to electric-powered vehicles.

The implications here foretell a discontinuous change for the utility industry, as it grapples with real-time technology information management and control of myriad devices outside *and inside* the consumer’s home that consume or produce electricity. Gone are the days when the sole device the utility interacts with is the meter. Soon, consumers will sell electricity back on the grid from their solar panels. They will park at a friend’s house and charge their car and expect to not get an angry call about the bill. Consumers will have “smart” devices including smart air conditioning and heating, smart lighting, smart appliances, smart circuit-breakers – practically anything that consumes electricity has computing power in it today and, if it doesn’t, thanks to Moore’s Law it will within 10 years. The static mechanical meter will be supplanted by a smart, two-way networked meter that can provide information into the house on devices *and* messaging from the wider area network.

In short, we are on the verge of an *enormous* networked dialog between the consumer, their devices, the meter and the electric power industry’s enterprise infrastructure. The consumer cannot accomplish their aims alone – they need information about when the grid is in danger, what the price of electricity is (and the cost to generate it), what utility programs they could and should participate in, and the transactional value and integrity of electricity they might put back into the grid via solar, PHEV or conservation. The utility cannot accomplish their aims alone either – they need maximum participation from consumers on a large-scale basis, considered free from “big brother” concerns or security and liability issues and be able to sell more of their product at a higher rate of return.

Consider just one example – a simple control management scenario. Using the exact same consumer and utility devices, one hour the utility may have the need to control electrical consumption (to reduce overall peak consumption on a very high-heat day) and the very next hour the consumer may realize they’re going away for the weekend and want to communicate via their cell phone that the house

should stop consuming electricity for the weekend. The exact same network, devices, meter and information are all needed for those two scenarios, and neither the consumer nor the utility are willing to pay for duplicate infrastructure to accomplish these seemingly identical task(s). Not to mention that the ability to communicate these needs could likely negate the utilities' need to consider a reduction of power to this household at that particular time.

## II. Implications for Utilities

The business implications for utility companies are huge. Should they get into “managing” devices in the home? Or continue to draw a line at their traditional demarcation point: the meter? Should they simply offer “information services” available at the meter demarcation point? Or should they offer robust programs that enable the consumer to get an unprecedented level of service from their energy provider? Should they stock some of these devices and sell them? Or should they provide a voucher to the local hardware store for the device? Or offer nothing at all and just hope the consumer buys an appropriate “smart” device? Do they get into the business of installing and/or validating devices? Or hope that all the devices “just work”?

An oft-ignored business implication for many utilities is the amount of purchasing power and/or control they have over the consumer device domain. Utilities have decades of experience with direct-to-utility vendors such as the meter and transmission grid suppliers. They often buy hundreds of millions of dollars of product. The opposite is the case with the consumer device market which, until now, the utility industry has virtually never purchased from and may continue to avoid. **However**, for the new energy management era to be successful, utilities need committed, well-capitalized and efficient consumer device partners who currently have little tangible incentives to “play” in the smart grid. This fundamental lack of incentive alignment is a business concern utilities, regulators and consumer device companies must overcome.

Beyond the business implications, though, there are tremendous technology implications – almost all of which require a level of interoperability that the industry has never before seen. As the historical point of demarcation was the meter, each utility could operate its grid mostly independently, without concern for what any other utility might do. However, inject consumer devices and a mobile consumer base into the mix and suddenly interoperability is no longer just a buzzword, it is a necessity.

Interoperability is required for at least 5 reasons:

1. **Affordability** will be the key driver of both the utility business case and the consumer's decision criteria. While consumers want the benefits they have grown accustomed to with digital and network technology, they also know that this technology is largely “cheap” and will expect it to continue to be so. This, then, mandates very high manufacturing volumes.
2. **Device heterogeneity** is a fact of life in the consumer market. A trip to any hardware or appliance store reveals an enormous variety of devices, all of which the consumer then has the option to review and choose. Consumers will shun any solution that forces them into a very limited set of device choices.
3. **Consumer mobility** means that some electricity devices in the house will move with the owner from utility district to utility district and the consumer will expect portability of that device.
4. **Consumer management** of their infrastructure will undoubtedly involve a mixture of the specific utility and other third parties – customers will expect the ability to move seamlessly between those third parties.
5. **High penetration** rates of “smart” devices are required to achieve the level of energy management needed to meet ever-constricting regulatory and societal goals.

Another essential technology implication for utilities is the consumer interface. Most utility technology decisions are devoid of any consideration for “ease of use” or “sizzle” because the demarcation point has remained outside the home. Most consumers never even look at their meter. In this new era, however, consumer adoption is vital and, hence, every ounce of ease and usability must be incorporated into any solution. Consumers simply will avoid a clunky “load control” system that is hard to install, hard to use and obtuse. Careful consideration has to be given to all facets of consumer experience.

### III. Technology Needs

There are four key areas for utilities to focus on to drive interoperability and provide seamless solutions from the back office through the AMI (or related AMR) network and into the home. These include:

1. **Device interoperability** to assure price competition and consumer choice. Because of the diversity of electric consuming products, device interoperability is an absolute must for success. The ZigBee Smart Energy Profile represents the most promising technology in this regard – primarily because it is the first technology standard that addresses *both* the network-level device interoperability (with the ZigBee protocol) **and** the necessary application-level device interoperability (with the Smart Energy Profile).

When a particular packet arrives, the device *must* be able to interpret and act upon that packet with context – the application or “smart energy” context. As most of the user interface(s) to these devices will be driven from afar – from a cell phone, a personal computer or an enterprise terminal – all of the context-laden messaging must be standardized within the device. Further, this standardization allows the market to decouple the device sale from the user

interface and “energy management” sale, further freeing up the market to compete, innovate and provide consumer choice. Lastly, device interoperability is required in order to bring down consumer prices – if devices are not interoperable, manufacturers would have to develop particular devices for particular utility markets and their volumes would be dramatically lower.

2. **Common Information Models** are required at the back-office-to-AMI-network interface because of the consumer’s need to employ various third parties on their behalf to help manage energy. Common Information Models must exist for transactional exchanges, demand response and load control exchanges, rich information exchange, security and electricity consumption/production information.
3. **Common Security Standards** are required by the device manufacturers to bring down the overall cost of devices and to ease manufacturing and operational complexity. They are also needed by various third parties to assure consumers have appropriate access to the infrastructure in and outside their home. Also, these standards are needed for consumer portability – when homeowners relocate with some of their more mobile devices.
4. **Network “bridging” technology** is required to enable various consumer demographic “use cases.” In no industry does one technology answer all problems in all domains. In the cellular industry, it is still impossible to get a signal at the bottom of the Grand Canyon. However, utilities have the added burden that they *must serve* all of their constituents – some of whom are the equivalent of “being in the Grand Canyon.” Rural versus urban requirements differ considerably and drive potentially different technology

decisions as do single-family homes versus apartments. In this kind of large-scale, requirement-for-ubiquity environment, technologies for bridging between one network technology and another must exist at a low price point. Unless a Common Information Model message can pass from one network (BPL) to another (HomePlug) to a third (ZigBee) in a seamless fashion, then solutions will remain largely proprietary and achieve minimal consumer adoption.

#### IV. Opportunities of Interoperability

It should be clear by now that there are massive opportunities to empower consumers, connect supply with demand, achieve environmental goals and ultimately save the planet. Employing a truly smart AMI, coupled with interoperable consumer-facing devices, will go a long way in helping this cause.

To summarize, specific opportunities that interoperability presents to utilities includes:

- Mass adoption
- Faster rate-of-return (environmental, grid reliability, regulatory mandates, etc.)
- Cheaper prices and lowered generation costs
- Vendor choice and the ability to cater to all geographies and demographics
- Avoidance of big-brother concerns, which in turn is regulatory friendly
- Ability to drive toward more price-connected rather than price-mandated environments
- Additional business opportunities for utilities and revenue streams outside of customer power bills
- A redefining of a century-old relationship between utilities and their customers
- Creation of a robust marketplace to solve these problems with innovation and creativity

Opportunities abound for consumers as well. These include:

- Lowering of electricity bills
- More efficient use of resources and cheaper prices of energy
- Consumer portability and mobility
- Vendor choice and wide availability of products
- Avoidance of big-brother concerns
- Faster time-to-contribution to make inroads to carbon reduction and lessened environmental impact
- Much deeper connection between behavior and implications on energy consumption. Take for example the Prius dashboard, which shows real-time consumption information about miles-per-gallon and dramatically alters people's behavior in how they consume and conserve gas.

#### V. Next Steps

With all of these opportunities and business and technology considerations, what is the next best course of action? What can be done to help move this initiative forward? Some recommended action includes:

1. HomePlug (and other) adoption of the Smart Energy Profile. The ZigBee Alliance has spent more than two years collaborating with the electric power industry to arrive at a good first-step application-level interoperable standard. Other networking technology organizations need to adopt Version 1.0 as-is and then work together, collaboratively, on developing a backward compatible Version 2.0. This will demonstrate to the utility *and* consumer market an ever-increasing scope of interoperability.
2. AMI-Sec work by appropriate utilities and vendors coupled with ratification of the recommendations. AMI-Sec (and AMI-Enterprise) are both driven out of the UCA User's Group and provide a set

of guidelines for the vendor marketplace to adhere to in order to meet the industry's needs. These guidelines should include interoperability guidelines for particular elements and layers of the security technology required.

3. AMI-Enterprise and Common Information Model work by appropriate utilities and vendors coupled with ratification of the recommendations. AMI-Enterprise is also driven by the UCA User's Group.
4. Coordination between the UCA User's Group with IEEE in the effort to ultimately fold in the guidelines, recommendations and requirements to develop interoperable standards within the IEEE structure. This will help convey another step-function change in the maturation of the necessary interoperability standards so that device manufacturers and utilities alike could adopt with more confidence.

# Interactions Between AMI and DA/DMS for Efficiency/Reliability Improvement

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## I. INTRODUCTION

Many electric utilities are deploying or planning to deploy Advanced Metering Infrastructure (AMI) to support current and future business needs. Besides improving the efficiency of traditional revenue metering, protection and collection and protection processes, AMI enables the utility to implement advanced metering features that support demand side management, including time-of-use rates and critical peak pricing. AMI provides a wealth of previously unavailable information that improves the electric utilities knowledge about the reliability and quality of the distribution system, and provides customers with information about their consumption patterns and ways to modify their consumption patterns to achieve cost savings and other environmental benefits. AMI is clearly a vital component of the “Smart” Electrical Grid of the future.

There is also growing interest in implementing Distribution Management Systems (DMS), another key element of the “Smart Grid”. The DMS is a decision support system that greatly improves operator visibility and control of the electric distribution system for improved power efficiency, reliability, and quality.

Individually, the AMI and DMS systems provide major steps forward in helping the electric utility achieve its future vision. However, leveraging the facilities and capabilities of these two systems through integration offers truly “world class” benefits in performance that go well beyond the benefits of the individual systems.

This paper summarizes the experience of a typical electric utility that is well on its way to accomplishing this goal

## II. AMI IMPLEMENTATION

The AMI system used by this utility is a fairly standard design based on today’s latest AMI technology. Major components include:

### A. - Microprocessor Based Customer Meters

The meters are used for recording and reporting interval data (kilowatts-hours, kiloVAR-hours) and outage (loss-of-

voltage) information. Each meter is equipped with standard AMR facilities, such non-volatile data storage, tamper detection, remote connect/disconnect capabilities, and two way communication facilities

### B. - Low Power, Low Bandwidth Two-Way Communication Facilities

These facilities handle communications between each meter and an associated “data collector” which communicates with up to 1,000 customer meters. Two types of technologies are used for meter communications: Wi-Fi and (conventional) power line carrier.

### C. - Data Collectors

These units communicate with groups of up to 1000 customer meters and transmit the meter data to the central billing location over a high bandwidth “back-haul” communication system. The data collectors include their own meters for obtaining measurements at the data collector locations. Data collectors are typically pole-mounted devices that are installed at feeder locations selected primarily for optimal communications with the maximum number of end-customer meters. One unique feature of this utility’s AMI is the placement of some data collectors and AMI meters at strategic feeder locations, such as major feeder branch points, to provide metering at these key locations. These additional meters and data collectors provide measurements that will enhance the performance of DMS applications, as described later in this paper.

### D. - “Back-haul” Facilities

These facilities provide wide-area communications between the data collectors and the centrally located Meter Data Management System (MDMS). For this utility, digital cellular facilities are currently used for handling the back-haul communication needs. However, the utility may use WiMax or Broadband over Power Line (BPL) to handle future requirements.

### E. - Meter Data Management System

This system manages the periodic and on-demand polling of meters and distributes meter reading data outage data from end customer meters to external systems that need this information (billing, CIS, outage management system, etc.).

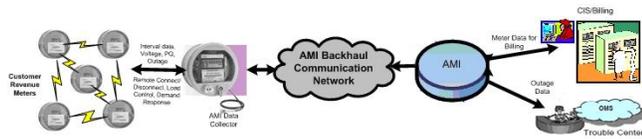


Fig. 1. Basic architecture of the utility's AMI system

Besides supporting the primary need for revenue metering, collection, and protection and outage detection, the AMI system also furnishes valuable information and facilities that enhance the value of the utility's Distribution Management System.

### III. DMS IMPLEMENTATION

The Distribution Management System (DMS) provides continuous monitoring and supervisory control of the utility's electric distribution system. In addition, the DMS includes numerous decision support tools and advanced application software to improve the efficiency of the distribution system (i.e., reduce losses), reduce demand, improve reliability (faster fault location and service restoration), pinpoint power quality problems, and improve equipment utilization, all of which are driving forces for the utility's vision for the electric distribution system of the future.

Key DMS applications are described below.

#### A. - On-Line Power Flow (OLPF)

) provides a three-phase, unbalanced power flow program for determining near real-time estimates of actual (voltage, current values) out on the distribution feeders. Available real-time feeder measurements from the "head end" of the feeder and from automated equipment out on the feeders and customer load models are utilized to improve the accuracy of the solution. Some of this information is obtained from the AMI system as described later in this paper. OLPF supports the operation of other DMS application programs, such as switch order management, integrated Volt-VAR control, and fault isolation/service restoration.

#### B. Integrated Volt-VAR Control

IVVC automatically determines optimal control actions to accomplish specified operating objectives (minimize energy consumption, reduce demand, etc.) without violating distribution system voltage constraints. IVVC control actions include LTC setting changes, capacitor bank switching (substation and feeder capacitor banks), and voltage regulator control

#### C. Fault Detection Isolation and Service Restoration (FDIR)

FDIR automatically detects feeder faults, and, depending on the availability of automated (remote controlled) switches out on the feeder, automatically isolates the faulted section of the feeder and restores service to as many customers as possible.

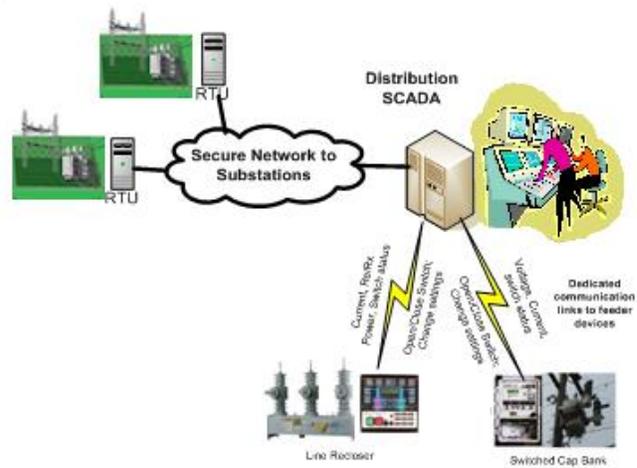


Fig. 2. The Utility's DMS architecture

### IV. BENEFITS OF AMI-DMS INTEGRATION

#### A. Communication Interface to Field Devices

The DMS applications implemented by the utility require two-way communications with voltage regulators, capacitor banks, and automated (electrically-operable) switches (reclosers, load break switches, etc) located out on the feeders (outside the substation fence). One of the most significant barriers to widespread deployment of remote monitoring and control of distribution feeder equipment is lack of reliable and cost effective facilities for communicating with this equipment. Challenges include communication system coverage (must communicate with devices located throughout the utility's service territory, many of which are obstructed by trees, buildings, mountains, etc.) and the very large quantity of separated devices. Often, the lack of suitable communication facilities is the primary reason why electric utilities do not implement continuous monitoring and control of feeder device.

To address this problem, the utility decided to leverage the AMI "backhaul" communication network to provide communication with the DMS feeder devices. The controllers associated with each DMS feeder device support TCP/IP communications, which facilitated the connection and use of the AMI backhaul network. Note that the AMI backhaul network only provided the communication channels for connecting the DMS "front end processor" (FEP) to the field devices. DMS FEPs communicate directly with the field devices (do not communicate via the AMI Meter Data Management System)..

#### B. Using AMI Data to Improve On-Line Power Flow Results

The OLPF program includes a "load estimator" function that assigns a current load value to each distribution transformer on the feeder using statistical load profile data obtained from load surveys of various general classes of customers.

While this method of load estimation produces results that are reasonably accurate, the OLPF results can be improved greatly if the load models match the actual power usage and energy consumption at each transformer. Since accurate load measurements are obtained by the AMI system on a daily basis, the utility decided to use the AMI data in the OLPF load models instead of statistical load profiles. The DMS uses actual load data from the previous days meter reads to perform its on-line load flow calculations. Some (not all) distribution transformers are equipped with meters that record the total load on each transformer. In cases where transformer metering is not available, the AMI system sums the readings taken from the individual customer meters served from each transformer.

This approach produces more accurate OLPF results than the traditional load estimation process which match the actual conditions out on the feeder. This will provide more accurate estimates of actual conditions out on the feeders which, in turn, enables the dispatchers to operate feeders closer to established ratings.

Another way to improve the OLPF results is to incorporate actual real time feeder measurements in the solution. The more real-time feeder measures, the more accurate the OLPF results will be.

Spare channels of the AMI “back-haul” communication network are used to acquire these additional measurements. Figure 3 depicts this approach. Note that it is not practical to acquire “near real-time” data from all AMI meters due to the sheer volume of data. However, the utility is able to acquire a small number of strategically-placed meters (less than ten AMI meters per feeder) every 15 minutes to support the continuous monitoring needs of the distribution dispatchers.

Strategic feeder locations include (but are not limited to) points at which the feeder splits into two or more major branches and feeder extremities (end points). Current flow measurements are acquired at feeder midpoint and branch locations, while voltage measurements are the prime interest at feeder extremities.

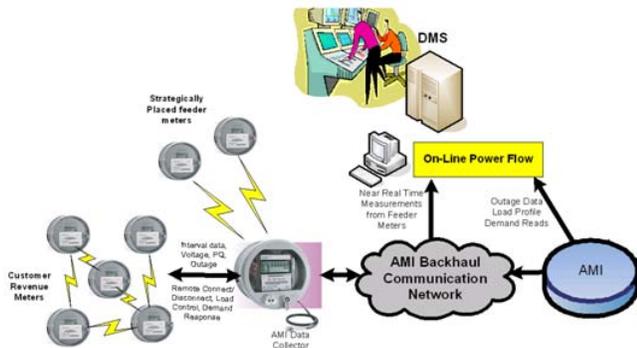


Fig. 3. Using AMI “back-haul” communication network to acquire additional measurements

### C. Using AMI Data to Improve IVVC Results

One of the most important DMS applications for this utility is Integrated Volt-VAR control (IVVC). This application determines optimal settings for all distribution voltage regulating and control devices (voltage regulators including load tap changing transformers and switched capacitor banks) to reduce electrical demand and/or electrical losses

IVVC uses the DMS OLPF to determine the current state of the distribution feeder and the potential impact of volt/VAR control actions suggested by the IVVC algorithms. AMI information, such as voltage and real and reactive power flow measurements, can be used by the IVVC application software to determine optimal settings for all devices. Since IVVC requires near-real-time data, AMI information is limited to a small number of strategic feeder locations.

Near real-time voltage measurements obtained from selected AMI meters at the feeder extremities provide positive feedback that voltage constraints are not violated by the recommended control actions. Figure 4 depicts the use of AMI for integrated volt-VAR control.

For this utility, AMI system data also played a key role in determining the load-voltage sensitivities used by IVVC.

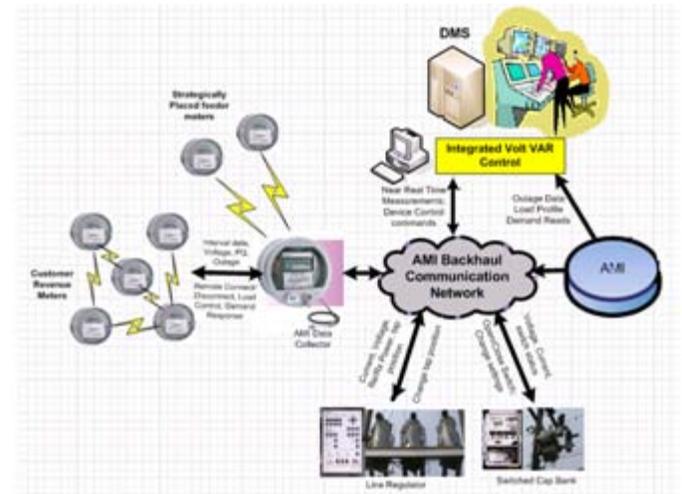


Fig. 4. Use of AMI for integrated volt-VAR control

### D. Using AMI Data to Improve FDIR Results

AMI systems, coupled with software tools provided by the Outage Management System (OMS), provide valuable information to assist distribution operations staff and trouble crews in determining the approximate fault location. The automatic metering facility provides loss of voltage information in the form of “last gap” messages from the meters that are traced back by the OMS software to the nearest upstream (closer to the substation) protective device (fuse, line reclosers, etc.). This narrows possible fault locations to the protection zone of the device.

This utility has obtained further improvements in fault location by acquiring the status of faulted circuit indicators (FCIs), via the advanced metering communications infrastructure.

Adding FCI information to the outage management process has enabled this utility to narrow down possible fault locations from an entire protection zone down to the portion of the protection zone beyond the FCI, thereby reducing overall fault investigation time. Figure 5 depicts the interface between AMI and DMS FDIR automatic restoration applications.

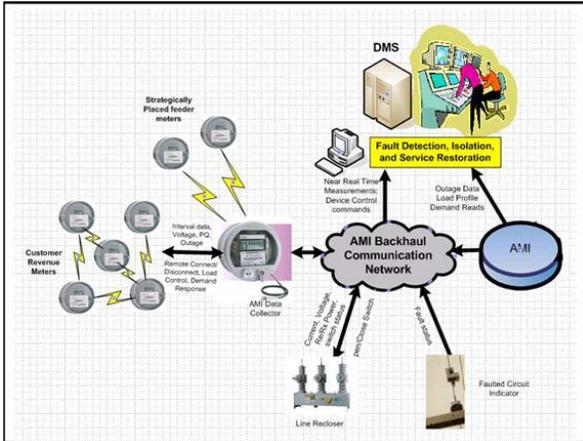


Fig. 5. Interface between AMI and DMS FDIR automatic restoration applications

## V. CONCLUSION

The implementation of an AMI system and a DMS are key steps towards the accomplishment of this utility's future "smart grid" vision. Integrating these two systems has enabled to achieve incremental engineering, operations, and asset management benefits that go well beyond that provided by individual "stand alone" systems.

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# Smart Grids and AMI: Understanding the Big Picture

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## Abstract

Utilities are deploying Advanced Metering Infrastructure (AMI) systems to collect and measure energy usage via digital meters installed in the customer's premises. Often, this is done with the belief that AMI alone is enough to achieve a fully enabled smart grid. In reality, however, AMI delivers a small subset of the potential benefits of a true smart grid and should be more accurately positioned as

AMI can be more accurately thought of as one of the early steps on the road to smart grid and the path from one to the other can be achieved through a broader understanding of the principles of interoperability.

one of the critical early steps along the road to a smart grid.

Data needed for a smart grid must come

from customer premise data captured by AMI, and also from generation, transmission and distribution assets. In addition, a Smart Grid must also be able to control switch status to re-route in real-time, and digital meters cannot do this in the grid.

To map out a logical smart grid path, utilities need to understand the distinction between AMI and smart grid, and keep the focus on the broader, long-term goal of deploying intelligent utility networks that help them drive high performance. This paper will provide an in-depth look at the variables that should be considered by utilities hoping to gain the full benefit of smart grid enablement. Looking at the big picture will help utilities map out a logical path aimed at leveraging AMI investments while also deploying Smart Grid as part of the journey to high performance.

## 1. INTRODUCTION

Utilities are focusing on deploying AMI systems that collect and measure energy usage via digital meters installed in the customer's premises. Very often, they are doing so with the belief that AMI by itself will give them a fully enabled smart grid capability. In reality, that is not the case. AMI is important, but it is not synonymous with smart grid and it delivers only a small subset of the benefits of a smart grid.

AMI can be more accurately thought of as one of the early steps on the road to smart grid.

Meanwhile, we are now seeing a broadening of the business case for moving beyond AMI into smart grids. Utilities have traditionally viewed AMI as a way to reduce meter-reading costs and achieve other billing improvements. As AMI implementations become more mature, utilities are increasingly interested in potential operational improvements and enhanced sustainability – in not only driving more efficient usage and simpler management of alternative energy sources, but also reducing the utility's overall carbon footprint. One US Midwest utility, for example, estimates that the smart grid will help it reduce fleet driving by some 50,000 miles per year.

With an eye to this growing range of benefits, a number of utilities are now looking for a path forward with smart grids. We think such a path exists and can be achieved through a broader understanding of the principles of interoperability. This understanding will also help utilities chart a course enabling them to take advantage of these new technologies and continue to keep them on the road to high performance.

## 2. SUPPORTING THE EVOLVING UTILITY MISSION

Many visions of the intelligent power grid have been put forth in recent years, such as the EPRI's Intelligrid vision, the GRID 2030 vision, and so on. The visions vary, but they also have common elements such as distributed intelligence, adaptive and self-healing functions, and end-to-end two-way digital communication across the entire energy delivery chain. At first glance, it may seem that an AMI network enables these features, but a closer examination of what these visions mean in practice shows why AMI, in itself, is not sufficient to support them all.

The vision of the 21st Century utility is complex, driven by diverse new business requirements. In general, utilities need to perform across three major types of activities.

- **Operations**—ensure the reliable, economic delivery of high quality, sustainable energy while minimizing carbon footprint to the degree required

- **Asset management**—optimize the value extracted from asset investments in terms of utilization and life cycle costs.
- **Customer services**—efficiently provide essential customer services and enable informed customer choice in the use of energy

AMI addresses some parts of all three areas, but its primary use lies in meter management, customer billing and to some degree, outage management. It cannot fully support the requirements for operations and asset management or the more expanded customer services of distributed generation. Smart grids, on the other hand, cover all three areas fairly extensively. When done right, the smart grid provides a range of functions, including:

- **Grid control** – grid state determination, Volt/VAR control, power flow control, loss management
- **Fault intelligence and management** – detection, classification, characterization and localization of faults; isolation of faults and rapid power restoration
- **Outage intelligence and management** – detection of outages, outage extent mapping, root cause determination, nested root cause detection, and restoration tracking
- **Metering** – usage measurement for billing support, load control point and home area network gateway
- **Power quality assurance** – remote monitoring of power quality and recording of power events and related parameters to support maintenance, planning, and mitigation steps
- **System performance and reliability assurance** – remote monitoring of power delivery and systems operational effectiveness to support maintenance, planning, and mitigation steps
- **Asset utilization measurement and control** – measurement of utilization in support of optimization processes for load flow
- **Asset health monitoring and system maintenance** – remote monitoring of asset health; measurement of stress factors and computation of stress effects for support of maintenance and replacement optimization and asset life cycle management
- **Energy usage management** – load shed control and demand response
- **Energy resource management** – adaptive integration of multiple energy source types, including traditional

Why isn't an AMI system enough to support all the areas listed above? Part of the answer is that a good portion of the data needed to support the full range of capacities needs to come from generation, transmission and distribution assets, not the customer's premises.

generation, alternative energy sources, and distributed generation and storage; minimization of carbon footprint

Why isn't an AMI system enough to support all the areas listed above? Part of the answer is that a good portion of the data needed to support this full range of capacities needs to come from generation, transmission and distribution assets, not the customer's premises. In addition, when it comes to distribution systems, some variables cannot be measured from the secondary of a distribution transformer, which is where the customer-premise meters reside. An example of this kind of measurement is voltage phasor angle transient

behavior during feeder voltage sags, which is used for fault detection and classification. Finally, for a grid to be truly smart, it is must be

able to control switch status so that power can be rerouted in real-time at the feeder level. Digital premise meters do not provide all the data necessary to support this capability.

What's more, grid behavior and the necessary automated responses span a wide range of time scales. Many behaviors and responses play out over days, weeks or even months, so timing is not much of an issue. However, others operate in sub-second terms, even down to milliseconds – take, for example, the real-time modification of a relay re-closing cycle in the presence of a permanent fault in order to minimize current surges through utility equipment. In some other cases, the required response may take place over a long period of time, but the measurements necessary to determine the proper response may have to be made on very short time scales, such as in the detection, classification, and localization of faults from voltage phasor transient behavior.

AMI meters and communications networks are designed with the bandwidth and latency to collect store and transmit billing quality data; they are not designed to support sub-second processing and transfers. This capability must be built directly into the transmission and distribution systems. Also, revenue quality meters and the associated AMI communications are not set up to provide data at different speeds, which is required to perform smart grid work.

### 3. THREE RULES FOR SMART GRID STRATEGIES

In essence, then, utilities need to look beyond AMI if they are to pursue true smart grid infrastructures. In doing so, they should bear in mind three key principals that will help them stay focused on that larger picture.

- **Principle #1:** Focus on observability and controllability, not the number of end points and the

speed of the communications network. What makes a smart grid smart is not how many sensors and devices it has or how fast they communicate, it is how well it enables utilities to observe the grid and all of its assets, and to control those assets for greater efficiency.

- **Principle #2.** Use business requirements, not technology, to guide design and technology choices: It is not uncommon for organizations to become enamored with a particular technology, device or system, and then try to make the problem fit this solution. For systems as complex as smart grids, such an approach is hazardous, to say the least. A strong methodology that starts with the definition of business drivers, determines technical requirements from those drivers, and then derives solutions from the requirements is critical to ensuring that a Smart grid solution delivers value to the utility.
- **Principle #3.** Design the infrastructure keeping the end game in mind. AMI requires high-bandwidth communications to allow large quantities of data to be transferred every now and then. Smart grid sensors require low latency to allow small quantities of data to be moved from the location where it is captured to another where a tool will perform an analysis. Failure to keep the end game in mind is likely to result in substantial increases in overall capital outlay, which will ultimately undermine the business case benefits of the smart-grid initiative.

Use business requirements, not technology, to guide design and technology choices: It is not uncommon for organizations to become enamored with a particular technology, device or system, and try to make the problem fit this solution

How can these principles operate in practice?

#### 4. EXAMPLE 1 – COMMUNICATIONS

Consider today’s discussions about the cost of smart grid communications. With the rapid and transient nature of much of grid behavior, many observers have concluded that advanced grid control and fault management applications would require very high speed communications—and with sensing being performed all over the grid, the result would be significantly increase the communication costs. Often, estimates of bandwidth requirements for smart grid sensor networks have been made by taking AMI bandwidth and applying a multiplier to account for additional smart grid sensing and data transport. The result, typically, is extremely large bandwidth numbers, especially under the assumption of AMI-type centralized communication architecture.

However, the good news is that this is not necessarily a foregone conclusion. By applying those three principles, utilities can address some of the assumptions that underlie those calculations, and they may find that their actual costs are less than such dire forecasts would suggest.

To begin with, a well-thought out business driven approach to smart grid capabilities has the potential to mitigate the communications burden. There are many possible levels of performance and capability in each of the areas of smart-grid functionality described above. At the same time, business requirements vary widely for electric utilities: For some, improving reliability is crucial, while for others, the integration of deeply penetrated distributed generation is foremost. In other words, most utilities will not need to excel in every aspect of the smart grid.

This issue should be addressed carefully and early on in the planning stage of a smart grid solution. Armed with the insight on desired performance levels at a capability level, the utility can then determine how much sensing is needed on the grid, how fast the data must be moved, etc.,. It may well be the case that the fastest analytics and responses are not required in many areas, allowing the utility to scale down its requirements (and investment) in the communications network.

Even if a utility’s business drivers dictate that it have high-speed measurement, analytics, and command capabilities, there are still

ways to mitigate the bandwidth issue. Distribution grid assets are organized hierarchically. This behavior supports organizing the information-processing layer of the grid in the same way. This means distributing intelligence to substations, grid devices, and line sensors – and even to meters. By placing intelligence at these points, utilities can achieve two ends:

- Reduce communications data volumes and therefore bandwidth requirements by performing processing locally (at point of sensing) and then sending exception messages instead of data to central systems.
- Provide scalability by converting data to information at each level in the hierarchy. This way, as information level increases, message volume decreases. With traffic aggregation at each level, data volumes remain roughly constant.

In short, this distribution of intelligence opens the door to ensuring observability while keeping communications traffic volumes and costs down.

#### 5. EXAMPLE 2 – INTEROPABILITY OF AMI WITH SMART GRID CAPABILITIES

AMI meters collect a lot of data from the customer premises. Many of the newer meters allow the utility to collect 15-minute time-delayed data on every customer including residential, commercial and industrial. This also means that every 15-minutes the utility had revenue-quality

consumption data across its entire network. This is compared to a severe lack of grid-level sensor data that exists today in the Distribution network. So, let us take stock of what the Utility actually has in its hands when an AMI system has been rolled out.

- It has **accurate consumption data** at the endpoints of its distribution network. All of this data is available at a centralized location every 15 minutes. The data captured here needs to be captured in its entirety and made available to all systems which require consumption data either in its raw form or in an aggregated form at a feeder level.
- The Utility's **GIS system** also has information on equipment, its characteristics and its connectivity model. The equipment connectivity data along with its characteristics will allow the systems to convert residential consumption data into feeder consumption data and so on.
- The marketplace has advanced systems like Distribution Management System (DMS) which has the **power system analysis tools** capable of converting the consumption data using the GIS-based model information into actual flow information across the Distribution network. Providing consumption data into a system like the DMS will allow the DMS to become more proactive in its analysis capabilities and deliver better information to the operator or the asset manager.

Knowing the flow information across the Distribution network provides for some significant strides into the Smart Grid benefits:

The list provided above is just a small set of examples which focus on the importance of interoperability between meters, the knowledge of system connectivity and their characteristics and the ability to feed this information into the systems to convert data into information. The benefits are listed below:

- Outage Management – from the power flow analysis, one can better identify the location in the network where the flow goes down to zero.
- Loss Management – Distribution losses account for a significant opportunity for improvement. Reduction in losses can be performed either through analysis of opportunities for re-routing of power or through better balancing of the three phases. In addition to reducing losses, this action also provides us with opportunities to extend asset life.
- Asset Management – the calculated power flow information allows for understanding of asset usage under different loading scenarios. Understanding asset

usage provides for more informed asset strategies and a better asset management philosophy.

- Demand Response – AMI systems are also providing 2-way interface with the consumer of power resulting in improved opportunities for manage and control consumption through new Demand Response mechanisms.

Many of these benefits are generally considered Smart Grid benefits. Also, to realize the full extent of the benefits, one would need Smart Grid capabilities – like better and more real-time sensing and control. However, until then, AMI capabilities have the potential to make a dent into those benefits without waiting for a full Smart Grid infrastructure.

## 6. CONCLUSION

To support high performance in smart grid efforts, utilities must look at a range of variables. For the communications system, factors such as latency and response to burst may turn out to be more important than raw bandwidth. In addition, a utility may choose to employ a multi-tier architecture for the communications network, so that it has a choice of communications performance levels available for each device.

Inter-operability of interfaces is also becoming an important issue as AMI systems are increasingly used to provide Smart Grid benefits. No longer just a part of the meter-to-cash process, the AMI system must now interface with outage management components and may be needed to support grid state measurement for grid control purposes. Interfaces can be crafted to advance interoperability of AMI and Smart Grid systems by recognizing that there are two primary types of data involved: operational data and event messages.

Interoperability comes from standards – standards between devices in the field, Standards between devices and systems, and Standards in diverse communications systems which will need to work with each other. Using appropriate standards such as XML messaging and service bus-oriented architectures are starts toward support for this level of interoperability. In the big picture, such inter-operability is crucial for the deployment of both AMI and Smart Grid systems: point-to-point integration and proprietary messaging are no longer acceptable in the highly integrated world of Smart Grids. Interoperability standards will allow the smooth flow of information between systems and increase the overall benefit from one set of investments.

Today, we are seeing a significant move towards AMI in the industry—and those efforts can be valuable and will move us significantly in the right direction. The key is to remember that AMI should not be an end in itself. AMI plans should not lose sight of the final goal of building the smart grid—especially when designing important

infrastructure components, such as communications and making full use of all the data. Keeping that focus will be vital to avoiding the need to “re-do” portions of the infrastructure—and the resulting increases in capital outlays—down the road.

Every utility’s situation is different, of course. But as the evolution of the smart grid continues to unfold, utilities should use these concepts to inform their visions and roadmaps for moving forward. Letting business realities drive their efforts, and being agnostic about technologies, will be a key to success. And by understanding the difference between AMI and true smart grid infrastructures, they will be able gain the full benefit of smart grids, and leverage their AMI investments in the continuing journey to high performance.

### **Biography**

Dr. Vadari is a Partner in Accenture and leads the Network Operations and Smart Grid area within the global T&D practice. His primary area of focus includes Transmission and Distribution Operations, Outage Management and Smart Grid. He has worked with both regulated and de-regulated utilities and energy companies. Many of his past roles have been as an architect focusing on designing technology, processes and organizational impacts. Dr. Vadari helps companies become high performers through transformation of their System Operations and the Smart Grid.

Dr Taft is Accenture’s Global Smart Grid Solution Architect. His primary focus is on the development of architectures, methodologies, and implementations for smart grids, including distributed and real time data management and analytics. He has worked with utilities worldwide and has an extensive background in real time embedded processing, signal processing, control systems, and advanced system architectures. Dr Taft has experience in the implementation for smart grids for both transmission and distribution, with special focus on grid fault analytics, outage intelligence, and asset monitoring.

# Real-World Planning for Smart Grid

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## Abstract

Future grids, under any label (e.g., Smart Grid, Intelligent Grid or Modern Grid, Grid of the Future, etc.), will utilize computer and communications technologies. The intent is to use available data readily available for making timely informed decisions to achieve business drivers of a utility company. However, it is important to note that utilities can realize such future grids only if they fully incorporate the following paradigms. This paper points out the real world considerations for moving towards such future grids.

First, Smart Grid - using this label for the future grids in this paper - is not a shrink-wrapped technology solution. Utilities need to integrate their legacy systems and equipment with the Smart Grid technology solutions. Interoperability issues should also include the already installed systems. Second, Smart Grid is unique to each utility. Utility planners do not just choose from a toolkit of technologies. They have to consider the optimal set of applications, the associated scope and the roadmap for their own utility. Then they would need to select the appropriate technology solutions, taking into account what is already in the field. Smart Grid is not a "greenfield" implementation. Third, regulatory ruling on cost recovery will be extremely complex because of the uniqueness for each utility. Benchmarking could become a major roadblock for Smart Grid implementation. Fourth, utilities should continue with their more traditional planning, albeit with more complexity due to so many automation technologies and non-traditional resources (e.g., distributed renewable, PHEVs and microgrids). Asset capacity needs to be available to enable utility planners and operators to use the information intelligently to better plan and operate the asset.

Only when utilities address such issues can they really arrive at a grid of the future.

## 1. INTRODUCTION

Electric power grids are undergoing a major transformation that is under a general banner called "Smart Grid". Others call it by different names such as IntelliGrid, Modern Grid or Utility of the Future. Essentially it is a world-wide movement to modernize the electric grid; the grid is not that different from the early days of Thomas Edison. This movement involves the convergence of the information technology with the electric power technologies to provide reliable electric services to customers in a safe, cost efficient and minimal carbon footprint manner. The electric services also provide choices to customers so that they can decide how they may want to change their energy usage pattern to minimize their power bills.

Imagine what life is like under a Smart Grid.... Mr. Smith gets up at 6:30 a.m. with the coffee freshly brewed already. He walks into the bathroom. The compact fluorescent lighting system detects his entry and turns on the light. He takes a comfortable and enjoyable hot shower; the hot water tank was fully charged by the wind generator in his backyard that has been running to charge up the fuel cell system and his two PHEV Volt vehicles. After shower, he puts his soiled laundry into the clothes washer, knowing that the soiled laundry will turn on when the electricity price is at the low rate. After scanning the newspaper in his laptop while sipping the coffee and Danish pastry, he notices that it is quite cloudy and wet outside. Quite a few tree branches were on the road. He is thankful that he did not experience any inconvenience from the windy and rainy storm overnight. Kissing his wife and kids goodbye,

he drives off in his fully charged Volt to his office, a 15-mile trip. He parks his car and plugs in to the outlet in the garage to charge up his Volt. The wind and rain are still beating down on the area in the morning.

In the middle of the morning, his PDA gets a message from ABC Power & Light Company that his house has a service interruption, and that the service will be restored in 35 minutes. He calls his wife and makes sure that everything is under control at home; his house experiences no service interruption because of the fuel cell system. Late in the afternoon, he leaves for home. Dinner is all ready and laundry is all done. His wife mentions that other than a flicker for an instant, the house did not experience any service interruption. After dinner, he looks up the electric bill on his laptop, and smiles; the bill is only \$20 for the month.

This is what life will be like under Smart Grid. How can utilities and stakeholders realize this vision? There are a number of premises that utilities have to incorporate when implementing Smart Grid in the real world. The more important ones are brought out in this paper.

## 2. PLUG-AND-PLAY SOLUTIONS

Smart Grid Solutions are not plug-and-play. There is a prevailing concept going around the utility, which is probably a direct transfer from the current microprocessor world. When we go into an electronic store and purchase a device with a USB port, we expect to be able to just plug in that device and use it (i.e., plug-and-play). Many utility planners expect something similar with Smart Grid. They expect Smart Grid solution to be shrink-wrapped. All they have to do is to find the right box off the shelf and plug that in. Unfortunately, Smart Grid solutions do not work that way.

A number of factors work against that frame of mind. First, utilities need to determine the best portfolio of Smart Grid technology solutions that would provide the maximum benefits to a particular utility. The utility operates under a set of business drivers under budgetary constraints. It is critical to recognize that these business drivers would push a utility to select an optimal set of Smart Grid applications. It is optimal in the sense that the utility would be able to utilize the applications to move the business drivers in a

way that delivers the best trade-off among a number of factors – system reliability, safety, environmental stewardship, customer choices, cost efficiency and regulatory pertinence. Thus, it is not just “looking up at a catalog” and ordering how many of this and that items we need. It is unique to each utility; “plug-and-play” concept is not readily applicable.

Second, utilities have to take into account the legacy systems. Just about every utility has some technologies related to Smart Grid. Many utilities have installed sensors that use protocols that are not compliant with the industry standards. They may have RTUs and master stations that are working satisfactorily. They may have a CIS or a home-grown data historian that is working well, though they may not have data access features such as ODBC. Therefore, utilities cannot just buy a Smart Grid system that follows the industry standards and expect it to work with the already installed legacy systems. A certain amount of customization may be needed. The development of these “one of” integrating applications could be necessary during this transition period to being a Smart Grid utility.

For Smart Grid technology solutions to function properly, it is important to understand the issue of *interoperability*. This issue could manifest itself in two forms: the ability for automation devices to communicate with one another, and the delivery of standard outputs from energy sources. The first form is compatible with what the traditional definition of “interoperability”. For instance, IEC standards such as IEC 61850 for field device communications and IEC 61968 for application programming interfaces allow for almost any application server to access data from a data mart for processing. Possessing this interoperability really facilitates the implementation of these Smart Grid applications. As another example, smart meters need to comply with ANSI C12.19 standard for data tables to ensure that stored data from meters can be retrieved and passed to data repositories. Indeed, if the interoperability issue is resolved, then individual devices can truly become “plug-and-play”. Currently, under EISA Title XIII, the federal government has designated National Institute of Standard and Technology (NIST) as the lead agency to define the standard protocols to ensure interoperability. The entire utility industry should work closely with NIST to expedite this process.

The second form of interoperability could be interpreted as standard. It pertains to distributed energy resources. With the proliferation of solar PV, wind generators, and PHEVs, it is important that the electrical output from such distributed generation and storage resources should subscribe to voltage and current standards, appropriate protective relays for the bidirectional flow of power, and power quality standards (e.g., harmonic content for different harmonics). The distributed resources should also include a standard set of remote monitoring and control capabilities that will be fed into a hierarchical control system. This will ensure that microgrids can function with integrity without introducing harm to the larger grid when interconnected.

Therefore, resolving these two forms of interoperability will go a long way towards achieving a Smart Grid vision.

### **3. TECHNOLOGY FOCUS IN SMART GRID**

As important as technologies are in Smart Grid, they should not be the sole focus. As pointed out in the earlier section, technology is only a means of delivering the desired applications that provide high value to utility business drivers. Vendors develop technology solutions to be sold. Utilities should focus on selecting the Smart Grid applications that will help them move the business drivers. Only after completing a business case study should a utility begin to find the technology solutions that can deliver those applications.

Technology focus also brings out another point: Smart Grid is not about technology breakthrough. It is true that Smart Grid applications could be better realized with some improved technologies. But these are only incremental improvements, not major technology breakthroughs. As a matter of fact, many of the technologies considered under Smart Grid are usually related to automation. This would involve some additional software or firmware development (e.g., some refinement on the peer-to-peer distributed intelligence feeder reconfiguration software such as taking into account the neighboring feeder's short term load forecasts). Or it could use a more robust and lower latency and cyber secure communications infrastructure. All these are rather small increments of improvement.

As a matter of fact, much of the foundation of today's Smart Grid applications was built as early as the 70's. USDOE funded much research into the integration of dispersed storage and generation (DSG in those days, now called DER, distributed energy resources) into the distribution system [1, 8]. EPRI had the foresight to promote the integration of load management (now slightly modified as Demand Response, DR, program) into the EMS/SCADA system dispatch [2]. A number of system vendors have been selling volt/var management application software as part of their DMS offerings [3, 4]. Even the methodology of conducting business cases that calls for separating benefits into different stakeholders' – utility, customers, environment and society – has been widely practiced in the days of DSM (demand sided management) during the 70's and 80's in California [5]. And even these were not "breakthrough" technologies in those days.

The challenge for the industry is to know that technology barriers for Smart Grid are not huge. We should not be daunted by this "technology mountain." In many ways, Smart Grid is becoming a branding umbrellas framework for collecting together a carefully selected set of technologies that will be optimal for a utility's business drivers.

### **4. SMART GRID IS NOT GREENFIELD**

In the US, utilities do not have the luxury of making Greenfield installations of Smart Grid. US led the world in full scale electrification. That was over a century ago. Unlike developing nations that can begin building an electric infrastructure afresh, US utilities has to contend with the many asset that have been installed many years ago. The challenge facing most utilities is how to migrate from the current aged infrastructure to a modernized and automated infrastructure, taking advantage of the advancement in IT. They cannot raze every stake in the ground and start afresh. Therefore, it is important that we focus on the how to integrate the new technologies with the already installed legacy systems as described earlier.

## **5. REGULATORY COST RECOVERY IS IMPORTANT**

It is important that regulators provide incentive for utilities to implement Smart Grid. Two aspects are worth noting. First, the investment required for Smart Grid is substantial. Brattle Group [6] claimed that the T&D investment is going to be valued at about \$900 billion over the next 20+years compared with an industry valuation of T&D assets at \$320 billion [7]. The Smart Grid investment could be 25% of the new T&D investment. That would be almost equal to the entire valuation of the T&D asset today. With such huge investment decisions, most utility executives are cautious about making such decisions. They may not be able to recover the cost under the current regulatory climate (for IOUs). Therefore, regulators have to be willing to reward the “early adopters”; otherwise, very few utilities would be willing to take this risky road. There is talk in the industry about allowing some percentage of the Smart Grid investment to be under cost recovery. The Senate has also recently passed a bill to allow smart meters to be depreciated over a shorter life – 10 years – than the traditional meters (30 year depreciating life)<sup>1</sup>. Again, this is all part of an attempt to minimize the risk of stranded asset.

The high Smart Grid investment also dampens what customer advocates would like to see – low rates. The large investment in Smart Grid will lead to higher rates. But in return, customers will see their environment becoming green for their children. The carbon footprint will be reduced, and global warming trend will be arrested. This is simply the hard reality we have to face as a community on this mother ship called Earth. We need to pay for the many years of injury we have inflicted to the environment.

Utilities and regulators should not depend on benchmarking to decide how the cost recovery should be devised. Benchmarking is finicky because the data base on Smart Grid performance is quite sparse. Unless the data monitoring system is standardized, the databases will not be consistent for meaningful comparison. Therefore, benchmarking should not be the basis for deciding the prudence of

<sup>1</sup> This was signed into law by President Bush as part of the Emergency Economic Stabilization Act of 2008 on October 3, 2008.

Smart Grid investment. As a matter of fact, the “prudence review” approach should not be practiced because utilities are making fundamental changes and improvements to their infrastructure, not incremental ones. Utilities have to assume major risk to invest in Smart Grid technology solutions, and risk is not easily linked with prudence, especially when one has the advantage of looking backward in time.

Electric rate decoupling is another issue regulators have to contend with when dealing with Smart Grid technology solutions. To decouple utility revenue from costs of programs that encourage energy efficiency allows utilities to invest in Smart Grid, which will also provide a much reduced carbon footprint for the betterment of the environment.

## **6. UTILITIES SHOULD CONTINUE WITH TRADITIONAL CAPACITY PLANNING**

Smart Grid applications could improve the utilization of the installed capacities in the grid, but utilities still need to continue with its capacity planning exercise. As well known in the industry, feeder fault location, isolation and service restoration function cannot deliver its full potential benefits in system reliability if the neighboring feeders do not have sufficient capacity to accommodate the switched load. Thus utilities should need to plan for capacity additions. Adding capacity is still needed under Smart Grid.

As a matter of fact, the planning could involve new technologies that may not be related to IT. For instance, we may want to consider advanced technologies such as amorphous material for transformers. Or utilities may want to use high temperature superconducting cables. All these will reduce system losses, which will contribute to the carbon footprint reduction.

But the planning exercise will be much more complicated because of the presence of microgrids, involving DERs such as PHEVs, solar PVs, wind and LEED buildings. All these load shapes will require a long history of data before we have the confidence in the spatial load forecasts. This uncertainty in database will linger with Smart Grid for awhile before we can gain confidence in our planning exercise involving Smart Grid.

## 7. CONCLUSIONS

Planning under Smart Grid will face a number of hurdles. Utilities need to recognize that Smart Grid is not just a toolkit of shrink-wrapped technology solutions. They do not just “plug and play”. Interoperability will solve the technology-related issues, but each utility has its own unique portfolio of Smart Grid technology solutions. Smart Grid is not just a technology issue. Actually it is not a technology issue because many of the technologies have been in existence for a number of years or even decades. In addition, utilities need to integrate with existing legacy systems, not totally Greenfield installations. That presents a challenge. The regulatory environment also has to be aligned to promote utilities investing in Smart Grid solutions. But utilities should continue to conduct their traditional capacity planning. Smart Grid technology solutions can only squeeze that much out of the installed infrastructure capacity. However, capacities need to be added to allow Smart Grid solutions to play.

With all these dynamics working in a cohesive manner, utilities will be ready to truly modernize their grids and be smart in using them to deliver services to the satisfaction of customers in a safe, efficient and environmentally beneficial manner.

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## BIOGRAPHY

Dr. ML. Chan is Executive Advisor of Smart Grid for Quanta Technology, LLC. He is also the China Executive Director of JUCCE's Smart Grid Cooperative in China. His areas of expertise are Smart Grid and the utilization of computer and communications system technologies to deliver power system reliability, performance improvement, and optimal asset management for utilities. He combines his power system planning and operations expertise to integrate renewable, distributed energy resources, demand responses and load management, AMI/AMR systems, Home Automation Network (HAN), feeder automation, substation automation, SCADA, asset condition

monitoring, condition-based maintenance (CBM), phasor measurement unit, wide area protection and FACTS technologies into a Smart Grid vision for utilities. The full realization of that vision is made possible when Dr. Chan guides utilities in developing and implementing enterprise IT system architecture to provide business intelligence for utility operations. His environmental resources background since the 70's also provides with significant insight to integrate renewable resources, demand side management and efficient energy building technologies into utility operations and planning. For more than 30 years, Dr. Chan has provided consulting services to over 70 utilities in the United States and around the world. He has published over 60 technical papers in the open literature, and has given many presentations and speeches in seminars and tutorials. He is the Chair of IEEE Power System Planning and Implementation Committee, and a member of Executive Advisory Committee for DistribuTECH Conferences. He is also on the Editorial Board of *IEEE Transactions on Power Systems*. Dr. Chan has SB, SM and Electrical Engineer's degrees from MIT, and PhD from Cornell University. Prior to joining Quanta Technology, he has worked with Energy Resources Company, Tetra Tech, Systems Control, Inc., Energy Management Associates, Inc., ECC, Inc., ML Consulting Group, SchlumbergerSema, and KEMA, Inc.

# **Utility Standards Board (USB): Utilities Develop Business Requirements for Interoperable Smart Grid Standards**

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**Abstract:** The Utility Standards Board (USB), a group of six major utilities covering 20 US states and Canadian provinces, has funded a unique effort in which these large utilities are developing the Business Requirements which will drive the development of de facto Interoperable Standards for the interface between the Advanced Metering Infrastructure (AMI) systems and the many utility back office and operations systems which are interconnected to the AMI via a generic “Enterprise Bus (EB)”. Although both the IEC TC57 WG14 and NRECA’s MultiSpeak program have addressed this AMI/EB interface, they have not yet addressed all of the requirements, particularly for the larger utilities. Gap analysis and coordination with these efforts are major aspects of the USB Smart Grid process, which will ultimately lead to more complete interoperable standards across the AMI/EB Smart Grid interface.

## **1. Introduction to the Utility Standards Board (USB)**

The Customer Care Research Consortium (CCRC), an executive forum of seventeen leading utilities for discussing strategy, co-funding research, and acting collectively on select issues, established the Utility

Standards Board (USB) in late 2007. The USB, currently including six of the CCRC utilities[i], is charged with developing de facto standards for the interface between the Advanced Metering Infrastructure (AMI) and the Enterprise Bus (AMI/EB interface), based on utility Business Processes which exchange information across that interface. This effort is coordinated by Navigant Consulting, Inc. and DEFG, LLC. with technical support provided by Xanthus Consulting International.

### **1.1 Scope of USB Projects**

The scope of AMI/EB interface is shown in Figure 1, namely the interface between the AMI systems which reach out to the meters and customer gateways, and the Enterprise Bus which connects to utility systems, including back office systems and certain distribution operations systems. Although implementation configurations of these systems can vary significantly, the basic architecture remains the same, with the Enterprise Bus acting as the conduit between the AMI systems and any other systems.

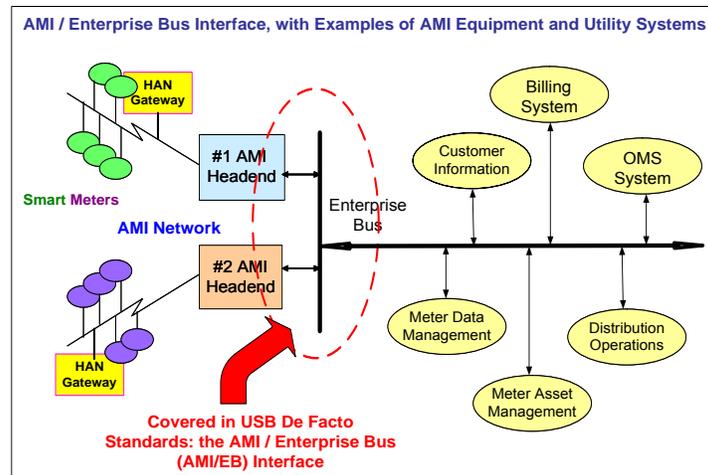


Figure 1: USB Scope: Interface between the AMI Systems and the Enterprise Bus

## 1.2 Breadth of USB Business Process Activities

The USB recognizes that there are a large number of business processes that will be utilizing the AMI/EB interface either directly or indirectly through using information that flows across the interface. The primary business processes are illustrated in Figure 2. The expectation is that the USB will focus on the business processes of the most interest to the utilities, taking them one at a time, rather than spreading their resources on attempting to undertake all of them at once.

## 1.3 USB Process

The USB fills a niche not served by the existing standards organizations by providing a focused methodology for utilities to develop their requirements.

The process used by the USB projects is:

- Develop extensive sets of Business Processes to act as sources of utility requirements

- Extract from these Business Processes the common information flows across the AMI/EB interface using Activity Diagrams
- After a gap analysis of the existing IEC 61968-9 draft standard and MultiSpeak documents, develop de facto standards to be specified and used by the USB utilities
- Provide input to the IEC TC57 WG14 for interface interactions not yet covered in the IEC 61968-9 draft standard. This process is shown diagrammatically in Figure 3.

Through dedicated work teams assigned to specific issues, the USB is dedicated to developing practical, de facto standards that utilities and technology vendors can embrace in the near-term and that the international standards bodies can incorporate into the global industry standards currently under development. The USB member utilities set the organization's research and development agenda working closely with the solution vendor community, other utilities, and other industry groups.

## Business Processes Utilizing the AMI/Enterprise Bus Interface

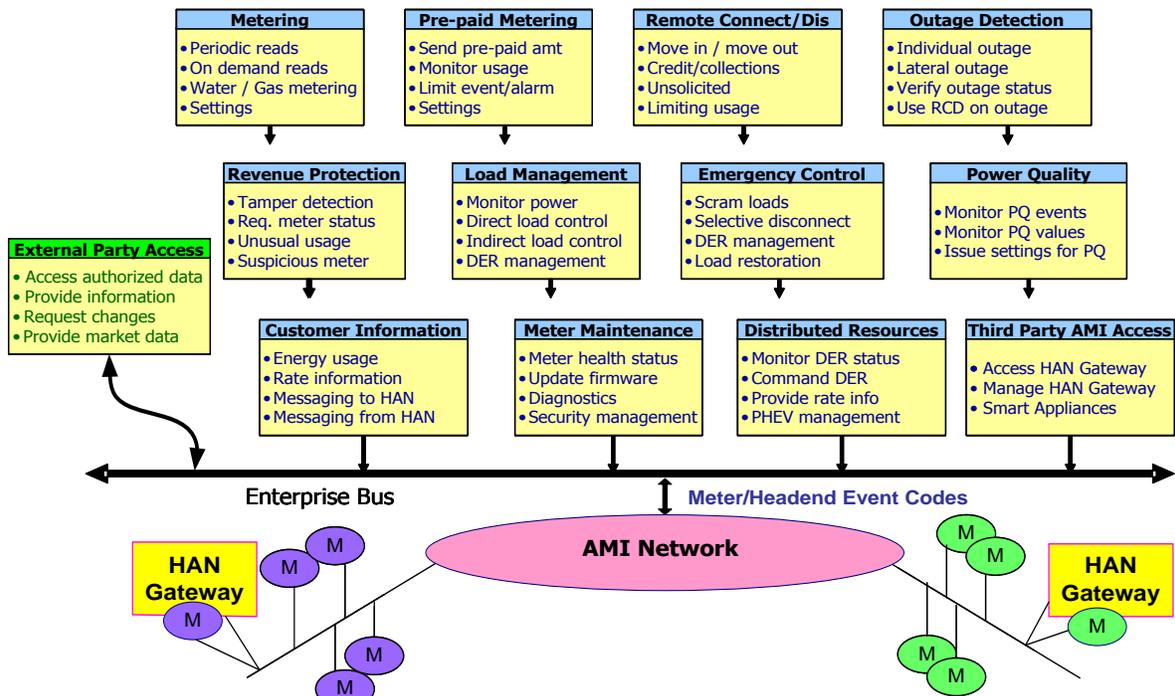


Figure 2: Primary Business Processes Utilizing the AMI/EB Interface

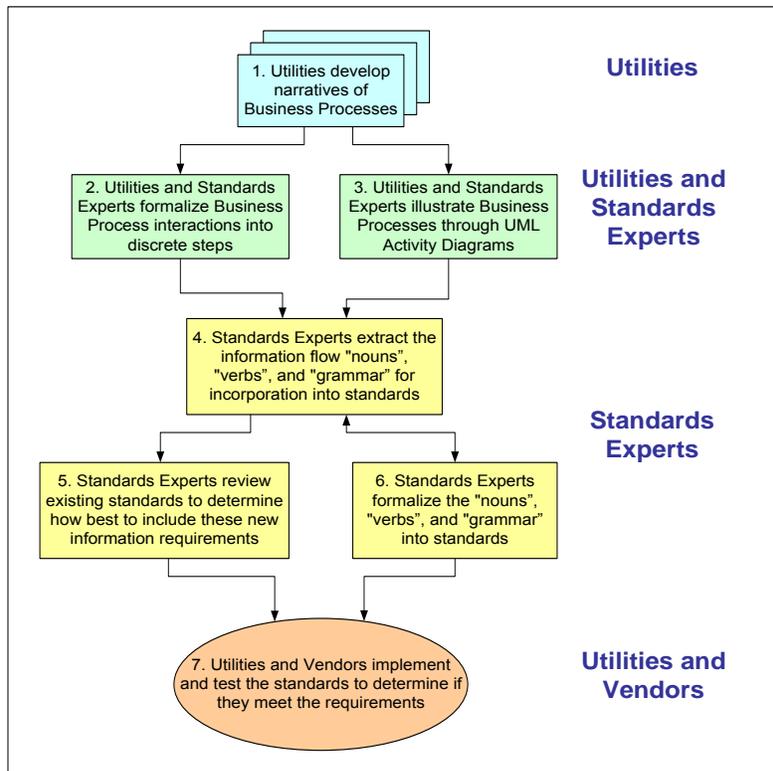


Figure 3: Procedure for Going from Business Processes to De Facto Standards

## 2. USB Project Teams

To date, the USB Leadership Team has approved and established the following three project teams:

- Meter/Headend Event Code (MHEC) project team
- Remote Connect/Disconnect (RCD) project team
- Outage Detection and Restoration (ODR) project team

As these complete their tasks, and as feedback is received from the teams, additional projects are expected to be authorized by the USB Leadership Team.

### 2.1 Meter/Headend Event Code (MHEC) Project Team

The MHEC project team is working to improve the organization, classification, and definitions for event codes that are received from the meters as well as those resulting from AMI issues. AMI and Meter Data Management (MDM) vendors were requested to provide a list of all event codes they either produce or encounter. Adding these to the existing ANSI C12.19

meter event codes and those developed by MultiSpeak, an exhaustive list of event codes was developed. These are being organized and combined into a draft set of event codes expressed in the XML Schema Definition (XSD) language. Preliminary de facto standards will be available for industry comment in Q4, 2008.

### 2.2 Remote Connect / Disconnect (RCD) Project Team

The RCD project team has developed business processes for remote connect, disconnect, and reconnect processes. These business processes include:

- Routine turn-on of service (move in)
- Routine shut-off of service (move out)
- Credit & Collections termination of service
- Credit & Collections reinstatement of service
- Local/on site shut-off of service
- Local/on site turn-on of service

- Credit & Collection Service Limiting
- Emergency Response / Load Shedding
- Unsolicited change of state of connect/disconnect switch including exceptions processing

- Remote Connect Basic Module
- Remote Disconnect Basic Module
- Unsolicited RCD Switch Basic Module

An example of the Remote Connect Basic Module is shown in Figure 4.

The RCD project team has developed Activity Diagrams of RCD Basic Modules consisting of:

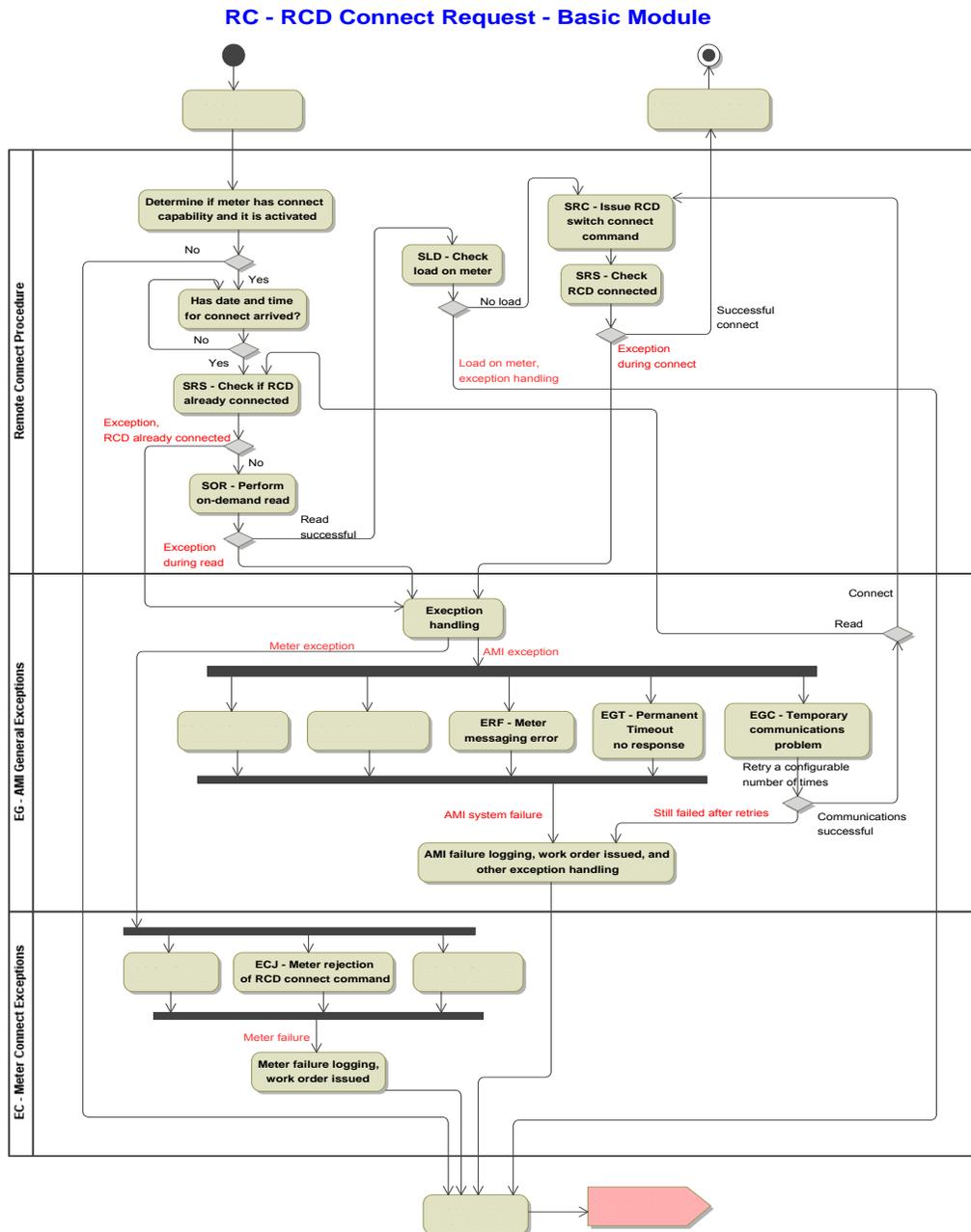


Figure 4: RC – Activity Diagram for RCD Switch Connect Request

These Basic Modules are comprised of Standard Modules which will become the de facto standards ultimately submitted to the IEC TC57 WG14. These Standard Modules include:

- **SRC:** Standard Remote Connect Command module
- **SRD:** Standard Remote Disconnect Command module
- **SLD:** Standard Check Load Value at Meter module
- **SUC:** Standard Unsolicited Connect Event module
- **SUD:** Standard Unsolicited Disconnect Event module
- **SCS:** Standard Check Status of RCD Switch module
- **SRE:** Standard for Determining Existence of RCD Switch module
- **SOR:** Standard On-Demand Meter Read module
- **Exx:** Many exception handling modules

The Standard Remote Connect Command module is shown in Figure 5.

From these Activity Diagrams, a set of RCD messages will be developed in XSD, similar to those in the IEC 61968 Part 9 and in MultiSpeak. Recommendations for additions and changes to the Common Information Model (CIM) RCD-related objects are being made.

These de facto standards will be made available for industry comment in Q1, 2009.

### 2.3 Outage Detection and Restoration (ODR) Project Team

The ODR project team, launched in September 2008, is starting the development of Business Processes related to outage detection and restoration services. The ODR process will be similar to the RCD process. The business processes will be completed in Q1, 2009, while the de facto standards development, if approved by the USB Leadership Team, will take place in early 2009.

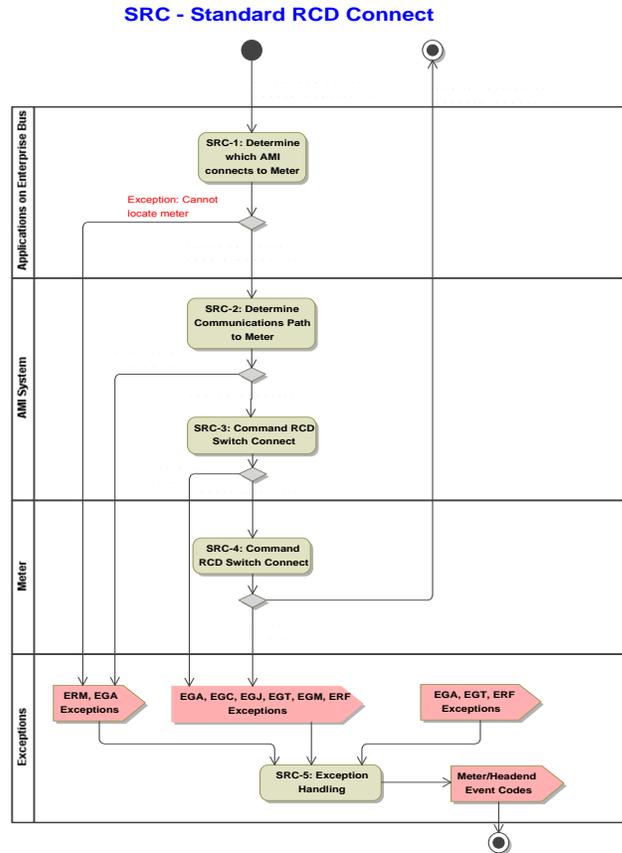


Figure 5: SRC –Standard Remote Connect Command Module

### 3. Conclusions

The USB is providing a fundamental, critical part of the Smart Grid concept, by establishing a concentrated, funded forum for utilities to discuss and develop the business processes which will lead ultimately to standards that truly meet the utility requirements, rather than just the vendor understandings of the utility requirements. All too often, utilities take a back seat in the standards development arena, relying on vendors and consultants to decide the sometimes very esoteric details in a standard. However, the USB determined that their interests were better served by becoming strongly involved both in developing their own requirements and promulgating the standards resulting from those requirements.

It is strongly urged that other utilities either join the USB or develop similar funded consortia to develop these business processes and the resulting standards that are required for true interoperability of the Smart Grid.

# Regulations, Standards, and Beethoven: How Regulations Shape Technology in Electricity and Telecommunications

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**Keywords:** Telecommunication, standardization, state and federal regulation

## Abstract

The nation's telecommunication infrastructure delivers copious amounts of information every day over a network of innovative technologies. In contrast, the nation's electrical transmission infrastructure delivers energy over a system that has been conspicuously void of revolutionary technologies. While advanced grid control devices and distributed generation technologies are currently available, the technological difference between telecom and electricity has resulted partly from the regulatory structures between the two industries. Reforms in the telecommunications arena removed barriers for new entrants, creating clear interfaces and incentives to expand capacity and increase consumer options. Partial deregulation of electrical transmission has resulted in the entry of generation and transmission at the most congested areas but no nationwide networks. With well-defined interfaces for grid connections, the electricity system could potentially mirror the competitive landscape of telecommunications. To encourage technological innovation, public decision-makers should enact regulatory structures that unify markets and remove technical barriers.

## 1. STANDARDS AS ROADBLOCKS TO MARKET ACCESS

Like the lowly three-pronged wall outlet, the RJ-11 telephone jack is a physical manifestation of the possibilities enabled by plug-and-play. The modems and fax machines of the 1980's utilized the analog telephone system for applications unimaginable just ten years earlier. To the credit of the electricity and utility industries, standards for one-way delivery of central station generated energy to end use devices have been well defined. The National Electric Code, independent safety certification labs such as UL and CSA, the WD-05 wall outlet standard, and a host of other entities, consumers can purchase a toaster in Mississippi and be fairly confident it will operate properly in Maine. To

complete the analogy to the RJ-11 jack, the electrical industry will need to implement a standard for small-scale upstream energy provision. The next major round of innovations in the electricity sector will emerge with a plug-and-play methodology for interconnection of distributed energy resources. The obstacles in the way of such a standard exceed those encountered in the development of the phone jack, but standards in and of themselves do not create markets. Current day "standards" for electric grid operations, like the telephone reliability criteria of the 1950's, actually serve to inhibit competition.

Before the RJ-11, arguments over reliability shut out otherwise innovative telecommunications products. In the 1950's and 1960's, AT&T used its monopoly over the telephone network to strengthen its monopoly over customer premises equipment. Western Electric, a wholly-owned subsidiary, provided equipment to the AT&T network and its customers. With one manufacturer, there was no lack of standardization. Instead, over-enforcement of standards restricted the emergence of a competitive equipment market. [1]

The Carterphone and the Hush-a-Phone were two non-AT&T products that provided additional functionality to end users. The Carterphone connected a two-way radio to a standard handset. The radio then enabled communications with remote locations and was originally developed for offshore oil platforms. [2] The Hush-a-Phone provided an enclosed chamber to keep a conversation private between a person and the mouthpiece. [3]

AT&T argued that the attachment of the Hush-a-Phone would compromise the reliability of the greater network, and notified end users that attachment of foreign devices was a tariff violation. The FCC, inexplicably convinced that a small metal box could cause harm to the network, banned the Hush-a-Phone in a 1955 decision. On appeal the DC Circuit arrived at the more reasonable conclusion that the Hush-a-Phone was "privately beneficial without being publicly detrimental." [4] Undeterred by the courts, AT&T interpreted the court opinion to apply to a very narrow definition of non-electrical accessories. In the 1960s AT&T

began disconnecting Carterphone users on grounds that attachment of this system was illegal. In 1968 the FCC ruled in favor of Carterphone, reasoning that the AT&T tariff did not establish clear criteria for harmful devices. [5] Combined, the Hush-a-Phone and the Carterphone cases marked the beginning of an FCC shift towards an open telephony equipment market.

Similarly in the electric sector, the Public Utilities Regulatory Policies Act (PURPA) wedged open the link between the electric transmission network of a utility and its generators. [6] The PURPA Qualifying Facility provisions forced vertically integrated utilities to buy from renewable and cogeneration sources, nurturing a market for energy from independent power producers. This separation of a network monopoly from an affiliated business was akin to the customer premises equipment cases in telecommunications, but the transformation was not yet complete, as the QF provisions were limited to specific generator technologies and ownership structures.

Following the 1992 Energy Policy Act, FERC began to institute open access for all types of generation, not just qualifying facilities. Beginning with Order 888 in 1996, vertically integrated utilities were required to provide non-discriminatory access to their transmission networks. [7] Some utilities embraced the open access provisions more wholeheartedly than others, and by 2000 a growing chorus of industry participants began calling for standardized procedures. In that year the Electric Power Supply Association wrote to FERC that "Uniform business practices would allow generation developers...to develop more streamlined procedures for their project developments. ...There is no rational reason for these requirements to vary from transmission provider to transmission provider." [8] FERC subsequently issued more detailed interconnection rules, culminating in the Standard Interconnection Agreements for generators above 20 MWs, generators less than 20 MW, and wind generators. [9][10][11]

While open access has been a pragmatic solution for a small number of large generator interconnections, the process struggles in areas where a large number of smaller generators seek interconnections. Interconnection requests are studied sequentially for reliability impacts, resulting in long delays as more project line up for studies. Tweaks to the process as recently approved at the Midwest ISO may provide a short-term relief to endless studies. [12] However, the physical grid and regulatory structures are not nearly robust enough to enable routine connections and disconnections of many small generators. Whether intended as an incumbent protection measure or not, the interconnection delays for new generation mirrors the arguments from the old AT&T: onerous requirements in the name of reliability are suffocating new competitive entrants.

## **2. WELL-DEFINED INTERFACES FOSTER MARKETS**

In 1975, FCC finally cleared the logjam to a competitive customer premises equipment market by standardizing the network connections, down to the dimensions of the telephone jack. The Part 68 rulemaking addressed AT&T's stated objection that equipment from other manufacturers posed a threat to the reliable operation of its network. Instead of relying on AT&T to determine if a device was harmful, the FCC would provide a generic definition to certify the safety of customer premises equipment. The now ubiquitous RJ-11 is among those codified in 47 CFR 68 subpart F. By providing one set of criteria, the Part 68 rules helped to streamline the process for interconnections and safety certification. [13] Between 1976 and 2004, the FCC registered 300,000 devices from 11,000 vendors. [14] In 2000, the FCC ruled certification for Customer Premises Equipment as a function that could be wholly provisioned by the private sector and transitioned to third party testing. [15]

Not only did the FCC action lead to competition and innovation in handsets, the new openness also sparked new uses for telephone lines. Instead of voice, the fax and the modem sent images and data. And the new devices themselves created new markets. For example, in the mid-1980's, late-night television commercials peddled pre-recorded answering machine messages. While dubious in value at \$14.95, one could purchase "Crazy Calls," which featured a baritone belting out "Nobody's home!" to the tune of Beethoven's Fifth Symphony. [16] Despite all the innovations from Bell Labs, it is difficult to imagine that a monopoly provider of standard beige phones [17] could have anticipated a demand for classical parodies.

Like telephony equipment, the load side and end use device market of the electric sector is relatively well developed. Independent certification bodies like UL and CSA ensure that energy consuming devices will not cause harm when attached to the grid and certify tens of thousands of products every year. Unlike telecommunications, pervasive standards do not exist for small-scale energy production devices at the retail level. If the electricity sector were voice communications, the sector could be said to have well-defined interfaces for listening to a conversation, but not for speaking to the other party.

In addition to customer premises equipment, the FCC also opened up interconnection points for long distance providers. In 1963 MCI was initially established to provide private lines to long distance business customers, but the company eyed the greater revenues from connection to the public switched network. AT&T resisted by arguing MCI would cherry pick the most profitable business, leaving AT&T with high-cost, low revenue customers. Through FCC filings and appeals, a federal judge finally ruled in

MCI's favor in June of 1980, connecting MCI to a much larger pool of customers. [18]

Merchant transmission, like long distance telephone services, has initially started by picking off the most profitable market opportunities, such as the highly-constrained interfaces between New York City, New England, and PJM. FERC has opened up all jurisdictional systems to merchant transmission entrants. However, merchant transmission projects are subject to the same interconnection queue delays as independent generators. Of the active merchant projects, interconnect studies have typically taken as much time to complete as the environmental impact statement. [19] Before the electricity transmission market can begin to emulate the common carrier attributes of long distance providers, these technical barriers to entry must be removed. Regulators will need to use policy to align and simplify the engineering practices that add years to project approvals.

### **3. REGULATIONS SHOULD FORM A BACKSTOP TO THE MARKET**

Excessive regulation stifled the equipment markets, but under-regulation can leave markets poorly defined. The diversity of cell phone technologies provides an illustrative example. During the development of the analog network in the 1980's, the Cellular Telecommunications Industry Association (CTIA) was formed to help decide on a single nationwide standard. In 1989, shortly after the CTIA selected TDMA as the new digital standard, the deregulatory-focused FCC assured a new technology developer that a spectrum operator would be free to use any protocol. The nascent Qualcomm then began marketing its CDMA system, with greatly increased capacity over the CTIA-endorsed TDMA standard. [20] The wisdom of the FCC's hands off approach is a separate topic altogether, though it should suffice to note that today the U.S. cell phone market is served through an assortment of leapfrogging, though incompatible technologies. If this patchwork of markets is not what electricity regulators have in mind, then an alternative approach will be required. In the ideal, balanced case, regulations safeguard the market against extreme tendencies, instead acting as a cause of market failure.

While the FCC Part 68 rules were a necessary step in the establishment of the customer premises equipment market, such regulations will inevitably lag technical innovation. For example, digital subscriber line services make use of copper wiring in ways that would violate Part 68 rules at the time the technology was deployed. [21] The FCC has generally permitted connections utilizing technological advancement pending industry consensus on modifications that would bring the Part 68 rules up to date.

Similarly, any new interface "standard" for the power sector should be considered as only a starting point. Technology tends to advance beyond that which is standard. Regulations that extend beyond a mere starting point would create a restrictive chill on innovation, as incumbent market participants use the force of law to raise technical barriers to entry.

### **4. INCREMENTAL REFORM AND THE PATH TO NEW MARKETS**

In order to transition to a robust market for energy's emerging technologies, incremental reform will be required to further open up the utility system. Regulators must avoid incumbent protectionism that plagued the telecommunications sector for decades. At the same time, energy regulators face distinct obstacles in attempting to transform fractured regions into nationwide markets.

The network nature of both industries can be used to protect an affiliate. As AT&T used its network to shield Western Electric from equipment competitors, electric transmission owners have the ability to discriminate against new energy service providers. While an explicit monopoly sanction clearly protects the incumbent, process delays are also equivalent to ruling for the incumbent. In 1968, the FCC noted the need for tariff revisions to interconnect customer devices, and formed a study group that met, without a successful resolution, for seven years. [22] A similar delay today in the electricity sector would only hinder the adoption of new technology.

If there were to be any silver lining, the nationwide telephone monopoly allowed the FCC to open up the customer premises equipment interface through a single regulatory proceeding. Unfortunately, no single agency has jurisdiction over the interactions between the end-use customer and the electricity provider. Today, electricity is delivered to end-use customers through a patchwork of more than 500 investor owned utilities, municipal and cooperative systems, and power marketing authorities. Transformation of the utility cost structure, from a provider of energy to a common carrier model, will take countless proceedings under the current system.

The FCC asserted its role in regulated customer premises equipment in a manner that would extend well beyond the retail-wholesale divide that has historically guided FERC policy. When deregulating the market for customer equipment, the FCC argued that "...because of the commonality of telephone company plant and facilities used to provide intrastate and interstate services and the indivisibility of such plant and facilities, rules governing interconnection of customer-owned equipment must be the same for interstate and intrastate services." [23] Thus the inability to separate local and long distance equipment gave the FCC authority to preempt state regulations.

To draw an explicit analogy between telecommunications and electricity, local telephone service would be akin to retail distribution, while long distance telephone service is akin to transmission. The FCC rationale has significant technical justification when applied to the electricity sector and if asserted, would give the FERC a significant tool in unifying practices across jurisdictions. Yet the decision to approve the deployment of retail equipment such as Advanced Metering Infrastructure has taken place exclusively at the state level. In the absence of Congressional authorization for preemptive authority, a uniform market will be difficult to achieve without significant coordination across individual jurisdictions. Therefore if a uniform customer interface is to be achieved, collaboration between the states will be essential. As passed in the Energy Independence and Security Act of 2007, the Interoperability Framework at the National Institute of Standards and Technology (NIST) will serve as one such coordinating mechanism.[24] State commissions could then voluntarily commit to mandating a set of interfaces as specified by NIST for retail use. A credible commitment to a uniform market from a sufficient number of states could mimic the benefits of a federally-established nationwide standard, drawing entrepreneurial innovation in the energy sector.

## 5. CONCLUSION

The telecommunications industry today may be viewed as a desirable end state, with a healthy marketplace for innovations in applications and hardware. The path telecommunications took to this state serves as an illustrative, though imperfect example for electricity. The issues of incumbent protectionism are similar, and through PURPA implementation and Open Access the FERC has established interconnection rules for generation sources. To be sure, energy regulators need not be concerned about the next market for pre-recorded answering machine messages. Unfortunately, the next round of innovations in transmission technologies and small-scale generation is hobbled by the lack of clear consumer-level interface points and cumbersome interconnection procedures at the transmission level. Uniform resolution of these obstacles, especially at the retail level, is further complicated by the distributed oversight caused by a lack of federal pre-emption. As the country looks to technological innovations in the next round of electricity infrastructure investment, regulators should take care to craft and coordinate policies that nurture the markets for such innovations.

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## Biography

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# Implementing the Smart Grid: Challenges and a Go-Forward Strategy

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**Keywords:** Smart Grid, Web Integration, Demand Response, Cloud Computing

## ABSTRACT

This paper discusses business drivers, and some of the requirements and challenges associated with Smart Grid implementation with a focus on information systems. It presents a go-forward strategy based on leveraging the power of the cloud computing and Software as a Service (SaaS) model.

## 1. BUSINESS DRIVERS

Many believe that the electric power system is in the process of a profound change. These changes are driven by the need for environmental compliance and energy conservation, the need for improved grid reliability while dealing with an aging infrastructure, and the need for improved operational efficiencies and customer service. The changes are particularly significant for the electric distribution side of the business, where “blind” and manual operations and electromechanical components of the previous century will need to be transformed into a “Smart Grid” to accommodate significantly greater levels of flexibility due to changes in load patterns, the need for demand response, the emergence of plug-in hybrid vehicles and on-site generation and storage.



Figure 1 - Business Drivers for Smart Grid

**The Environment:** Environmental issues have moved to the forefront of the utility business with emerging requirements for Renewable Portfolio Standards (RPS), limits on greenhouse gases (GHG) and implement demand response and energy conservation measures. In response to the Section 1252 of Energy Policy Act of 2005<sup>i</sup>, many state regulatory commissions have initiated proceedings, or have adopted policies calling for demand response and implementation of the enabling Advanced Metering Infrastructure (AMI). These have been further augmented with Energy Efficiency Resource Standards (EERS)<sup>ii</sup>. 26 States and the District of Columbia<sup>iii</sup> have now established RPS targets with California leading the pack requiring the IOUs to have 20% of power they serve to be produced by renewable resources, by 2010. Regional initiatives to cap greenhouse gases are being formalized in the West<sup>iv</sup>, with CO<sub>2</sub> Cap-and-Trade being rolled out in the Northeast<sup>v</sup>. Compliance with these policies will require significant changes in utility operations and will require considerably greater degrees of information management and control.

**System Reliability:** Reliable supply of electric power is a critical element of our economy. The aging infrastructure of our transmission and distribution networks, combined with the need for new operating strategies for environmental compliance threatens the security, reliability and quality of supply. The power grid will be further stressed with the introduction, and perhaps rapid adaptation of plug-in hybrid vehicles (PHEV)<sup>vi</sup> that could potentially double the loading on certain distribution circuits if the charging time is not controlled. Major upgrades to electric power delivery infrastructure are costly and time consuming. However, significant room for reliability improvements exists through better monitoring, automation and information management. Asset management strategies can deliver further improvements with condition monitoring and condition-based maintenance.

**Operational Excellence:** Enhancing operational efficiencies, meeting customer and market needs, and improving supply economics have always been among the top business objectives of utility executives. These pose extra challenges as they face new environmental requirements; and have to deal with an aging workforce,

higher fuel costs, and ever increasing customer expectations for reliable and low cost supply, new services and timely information.

## 2. SMART GRID SCOPE

A “Smart Grid” vision is achieved by bringing together enabling technologies, changing business processes, and a holistic view towards the end-to-end requirements of the grid operation. The focus of this paper is on the required information technology, while we do recognize that policy, organizational structure and capabilities, and business practices and business processes play an important role in the implementation of Smart Grid strategies, since they involve cross-functional and cross-organizational activities.

Many utilities have implemented various pilot projects and limited scope deployments of Smart Grid applications with a minimum impact on existing operations and systems. A broad-based Smart Grid implementation may have significant impact on many of the utilities spanning systems and processes from metering and customer services to grid operations, planning, engineering and power procurement. Some refer to Advanced Metering Infrastructure (AMI) synonymous to Smart Grid. Even though AMI plays an important role as one of the enabling technologies, Smart Grid is much broader concept, not only requiring customer metering, but also addressing the complex issues associated with grid operations, considering the reliability, quality and carbon footprint of the power supply, and the economics of supply and demand.

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.

It is expected 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.

The traditional power delivery paradigm of large remote power stations with central dispatch, long transmission lines and distribution system primarily designed to deliver power from transmission substations to load centers with established load profiles is evolving to a new model. This model should accommodate greater levels of dynamic load and load elasticity due to demand response, and generation and storage resources on the distribution grid, generation closer to the load, need for micro-grids, and considerably higher levels of intermittent generation on the transmission system<sup>vii</sup>.

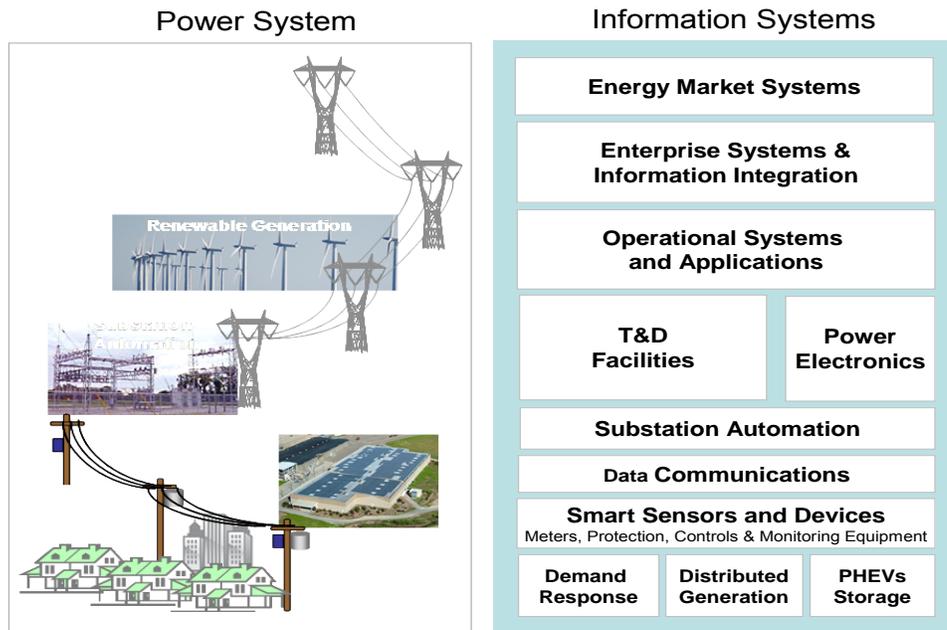


Figure 2 - The Smart Grid Enabling Technology Stack

These changes may not only require changes to the power system capacity and capabilities, but will also have significant impact on the information technology (IT) needs. The IT impact is particularly significant for the distribution grid where very traditionally very limited sensors, automation and information is available. Figure 2 presents the two required technology capabilities that make a smart grid possible, i.e., power systems infrastructure and Information technology capabilities. This paper addresses some of the issues associated with the latter.

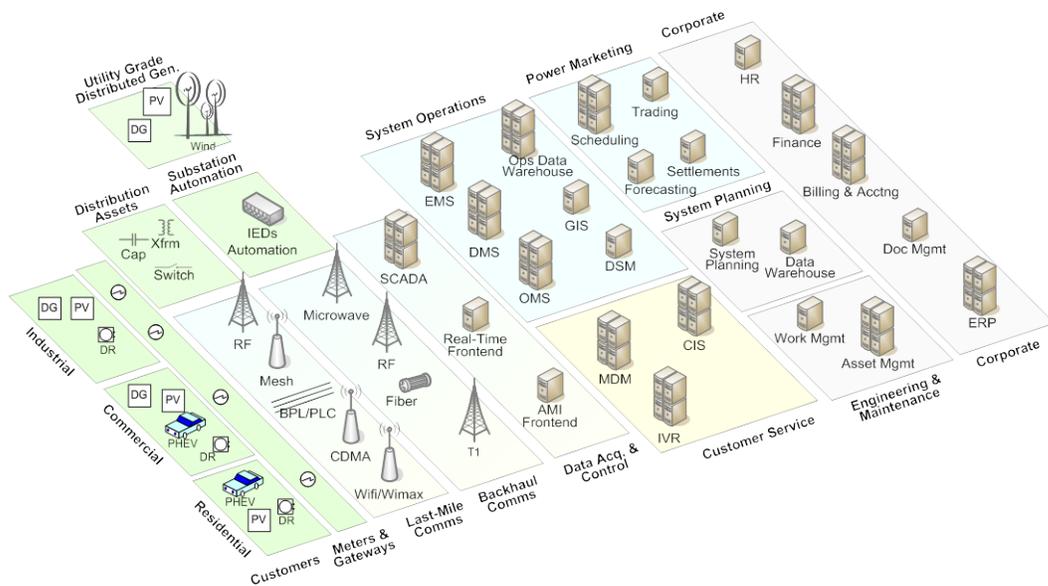
### 3. INFORMATION INTEGRATION REQUIREMENTS

A broad-based implementation of Smart Grid capabilities will impact many of the existing utility operational and information systems.

Figure 3 presents an overview of typical utility business functions and systems that perhaps will be involved in a broad-based Smart Grid implementation. In addition to advanced metering and communications infrastructure to enable demand response, distributed resource management, and automation functions, the deployment also involves a number of enterprise and operational software applications and information systems. These include SCADA and other field data communications, acquisitions and control systems for DER, feeder and substation automation, systems for customer services, planning, engineering and field operations, grid operations, scheduling and power marketing, as well as corporate enterprise systems for asset management, billing and accounting, and business management.

This can be further illustrated in an example. Many expect that by 2012-2014, there will be significant number of PHEV's and utility grade solar generation (0.5-2 MW) on the distribution grid. This may create localized congestion (i.e., loading in excess of capacity, or voltage/VAr deviations) on the distribution feeders or secondary circuits. Also, to enable a broad-base demand response many expect that dynamic and market based rates may become the default retail tariff in many regions with AMI capability. This will require significantly higher levels of monitoring, controls, automation and coordinated information management 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. This can be achieved with a combination of a centralized analysis and control, congestion and market based dynamic pricing, and distributed intelligence. This will require considerable changes to the existing network operating practices. As is illustrated in Figure 4, 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.

**Figure 3 – A view of utility information systems impacted by Smart Grid strategies**



Such implementations should also address engineering and maintenance of aspects of the transmission and distribution assets to ensure a high degree of system reliability while optimizing Operations & Maintenance costs. 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 smart 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.

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

Currently most utility companies have limited interoperability capability across the applications associated with system planning, power delivery and customer facing operations. In most cases, the information in each organizational “silo” is not easily accessible by applications and users in other organizations. These information silos correspond to islands of autonomous business activities. A Smart Grid strategy requires information integration across these islands of information. It is also 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.

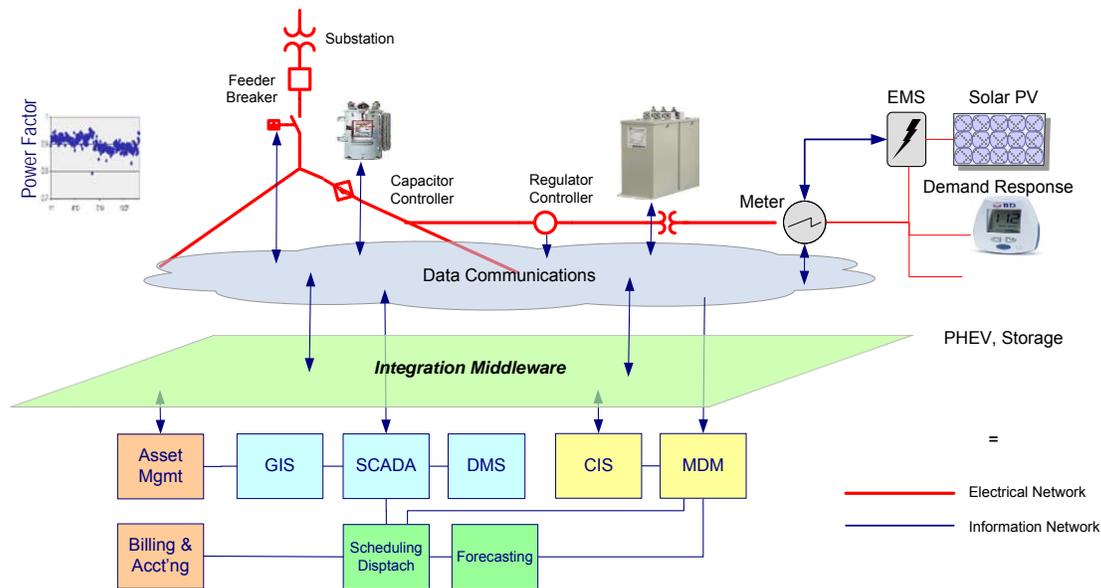
#### 4. CHALLENGES WITH IMPLEMENTATION OF SMART GRID IT SYSTEM

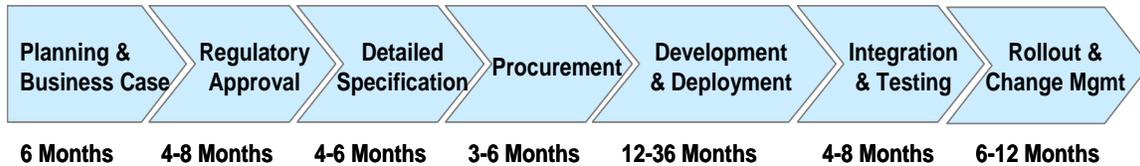
A broad-based implementation of such information systems poses many challenges in the highly regulated utility business environment. The regulatory environment imposes significant lead time for non-conventional large scale projects, as illustrated in Figure 5. A broad-based implementation of the required information technology infrastructure may require 3 to 5 years in the current business environment. Even though the lead time can be shortened by conducting activities in a parallel fashion, there are other complicating challenges.

Some of these challenges include:

**Not a Clearly Defined End-State** - the expected changes in demand patterns, penetration of distributed resources, PHEVs and other driving forces are a function of many external factors including economy, oil prices, political and regulatory environment. As a result the condition of and the timing of the end-state is not well defined such that detailed technical and business requirements can be developed.

**Figure 4 - Systems required to support high penetration of distributed resources**





**Figure 5 - A Broad-Based Smart Grid IT Implementation Timeline**

**Incremental and Evolving Nature of the Applications -**

Many of the changing requirements are incremental with respect to the existing capabilities. In many cases, some of the existing capabilities need to be augmented to address the emerging requirements, e.g., added capabilities for management of renewable and intermittent resources.

**Touches many of the legacy business functions and systems -** Smart Grid functions touch many of the existing operational systems and business processes. These existing capabilities need to be leveraged for a successful implementation. Many utility executives and operational personnel are very concerned about the potential negative impact of the new capabilities on the on-going operations.

**Has to be Rollout With a Minimum Impact on Existing Operations -** Reliable supply of electric power can not be disrupted, and incremental additions should not have any negative impact on the existing and un-affected operations.

**Requires data interfaces with external and 3<sup>rd</sup> party systems -** Utility Smart Grid applications also need to be interfaced and integrated with external users and systems, including customers, service providers, energy markets, smart charging stations and PHEV on-board computers, to name a few.

**Lack of Standards and Established Business Practices -** Many of the Smart Grid applications are new, with limited available industry technical standards and established business practices.

**High Cost of Implementation -** The high cost of broad-based implementations needs to be justified, especially if it is rate-based capital investment.

**Implementation Time -** Due to the required long lead-time, projects need to be planned a few years in advance of the required roll-out time.

**5. A GO FORWARD STRATEGY – LEVERAGING THE CLOUD**

One of the emerging, and perhaps game-changing, developments in the IT industry has been the use of the web (the cloud<sup>viii</sup>) as the computing and information management platform to enable composite applications, integration of data and capabilities from multiple diverse sources to deliver powerful functionality over the web.

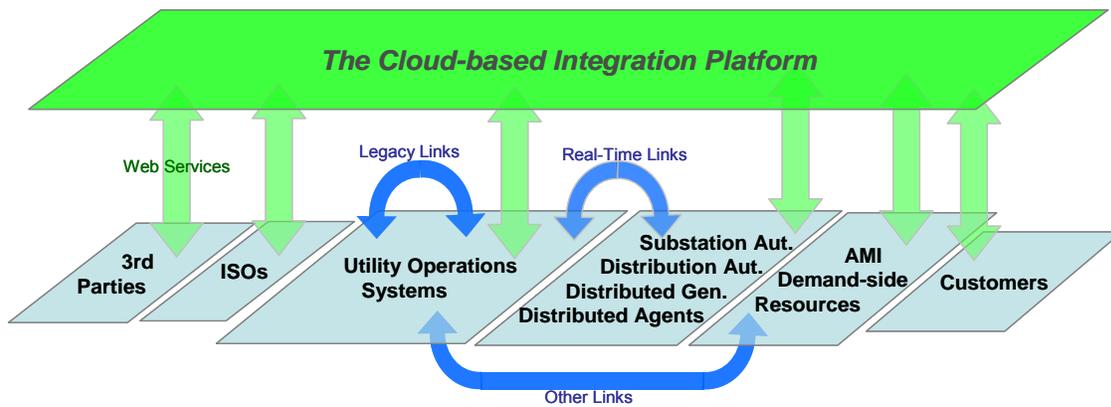
These applications are hosted in data centers that offer extensible computing capabilities to provide the flexibility, scalability and security needed for many of the emerging smart grid applications, without major impact on the legacy systems behind the utility enterprise firewall.

New applications can be introduced to augment the existing utility capabilities using this model. Many of the Smart Grid applications require integration of information from diverse systems outside of the utility enterprise firewall, and require flexibility, extensibility and scalability needed to support the potentially fast changing business and customer needs, e.g., support for PHEVs, or management of distributed energy resources.

provides a conceptual illustration of this model, where the web is used as a platform for incremental addition and integration of new Smart Grid applications with utility legacy systems and external systems and users.

A cloud-based Smart Grid strategy can address many of the challenges stated in Section 4 of this paper.

- It provides a cost-effective approach for incremental/phased roll-out of functionality as the needs arise, without a need for fork-lifting the legacy systems;
- It provides the capability for securely integrating the new capabilities with existing internal and external systems, and connecting those to users and customers;
- It provides a framework for easy integration of third party and partner capabilities;
- It allows evolving the business capabilities without the need for changing installed systems;
- It allows implementing the new capabilities in parallel with the existing operations and systems while minimizing impact on the on-going business; and
- It leverages Software as a Service (SaaS) model, minimizing capital outlays and project implementation time.



## 5.1 Sample Applications

Figure 7 presents sample Smart Grid applications suited for implementation under this model. These include:

**Demand Response and Distributed Resource Management** – Capabilities to link information from advanced metering, load management equipment and distributed energy resources with distribution operations and ISO/RTO demand-response markets in order to optimize economics and improve reliability of power supply. These include:

- Communications with Demand-Side Resources
- Forecasting and Monitoring Demand-Side Capabilities
- Aggregation, Scheduling / Bidding, Dispatching and Settlement of Demand-Side Resources
- Registration, Administration and Management of Demand-Side, and Distributed Energy Assets

**Renewable Resources and Greenhouse Gas Emissions Management** – Tools and services for management of renewable energy assets including:

- Forecasting, Tracking and Reporting Compliance with Regional Renewable Portfolio and Greenhouse Gas Standards
- Management and Trading of Renewable Energy Credits and Emission Allowances – support Cap-and-Trade operations
- Scheduling of Distributed and Intermittent Resources into energy markets
- Support Operations of renewable and intermittent energy resources

**System Reliability Improvements** – Address operational challenges and opportunities due to higher distribution loads (PHEVs) and availability distributed generation and demand response resources, including

- Improved outage management functions

Figure 6 – Using the Cloud for Smart Grid Applications

- Distribution grid monitoring and support for distribution automation and micro-grid operations
- Work Management and Mobile Workforce Management Interfaces

**Asset Management** – OATI provides tools and applications to augment the existing Asset Management systems to support Smart Grid operations, including:

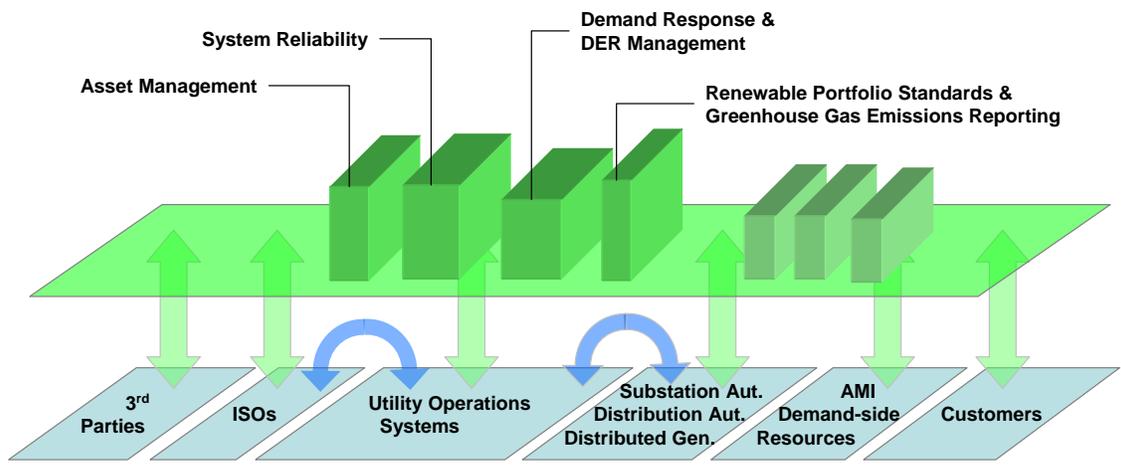
- Equipment condition monitoring and condition based maintenance support
- Load Profiling and Equipment Loading Analysis

## 5.2 Data Integration

A typical Smart Grid application may require data integration and management for:

- 1) “real-time” events and messages that require immediate attention, and
- 2) Semi-static data, bulk data and transaction-based information. Often this data need to be coordinated with other databases to ensure single-source-of-truth and data consistency at all times.

For example, a customer or a feeder outage notification is considered as a real-time event, but the exchange of network connectivity models can be considered as a bulk data transaction. Real-time data interactions can be further subdivided to critical grid operational data, especially those related to the bulk power, e.g., substation SCADA, switching and system security data, and those that are needed for the distributed resource and demand-side operations, supply economics, and distribution grid and equipment condition. The potential latency of the cloud-based data exchanges (1-2 seconds) may limit its usefulness for mission critical real-time applications, e.g. substation SCADA, however, it can easily support non-critical real-time and transaction based data integration requirements.



# MultiSpeak® and IEC 61968 CIM: Moving Towards Interoperability

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**Keywords:** Interoperability, MultiSpeak®, CIM, enterprise integration

## Abstract

One of the goals of the GridWise Interoperability Framework [1] that is clearly identified 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 the two most widely implemented standard data models in the electric utility industry, MultiSpeak® and the International Electrotechnical Commission (IEC) Common Information Model (CIM). Creating such a bridge will eventually permit interoperation among MultiSpeak- and CIM-compliant applications. Such interoperation will make it easier for electric utilities to build integrated automation systems that make use of the best of both standards.

A recently announced collaboration between MultiSpeak and IEC Technical Committee 57, Working Group 14 (WG14) is designed to build the necessary bridge between the two standards.

The first step in the collaboration is to create a mapping between the data and messaging models so that a two-way electronic conversion can be created between CIM messages with appropriate CIM payloads and MultiSpeak web service method calls with corresponding MultiSpeak data payloads. A set of IEC standards will be issued to document the mapping. The second step in the collaboration is to create a set of CIM profiles that will implement the capabilities inherent in MultiSpeak.

The authors will discuss the planned technical approach to achieve the goal of interoperation and illustrate the approach with examples.

## 1. BACKGROUND

Utilities continue to seek standards-based integration to limit the cost and risk of implementing proprietary automation solutions. The two most commonly applied integration standards in the electric utility industry are the MultiSpeak® specification [2], which has been developed and is maintained by the MultiSpeak Initiative, and the Common Information Model (CIM) [3] [4] [5], which has been developed and is maintained by Technical Committee 57 (TC57) of the International Electrotechnical Commission (IEC). An initial approach to interoperation of systems implementing the two standards was presented in [6].

Up until now, MultiSpeak has focused on integration of applications used in the distribution portion of electric utilities. MultiSpeak interfaces have been available and implemented since 2001. MultiSpeak integration is known to be in operation at over 250 utilities. Adoption of MultiSpeak has been primarily, but not exclusively, in distribution utilities in the United States. Version 4.0 of the specification, which is expected to be issued in early 2009, will add support for transmission system modeling, work management and internationalization of the data model. The MultiSpeak Initiative has supported a robust, independent compliance and interoperability testing program on all defined interfaces since 2001.

The standards family maintained by TC57 covers all aspects of a vertically integrated electric utility. CIM integration is known to have been implemented at dozens of utilities worldwide. TC57 supports interoperability testing on two data exchange profiles: the common power system model (CPSM) [7] for the exchange of transmission system models and the common distribution power system model (CDPSM) for the exchange of distribution power system models. In addition to supporting basic inter-application integration, the CIM is increasingly being used by utilities

as a cornerstone for their Enterprise Information Management programs. [9]

Working Group 13 (WG13) of TC57 maintains the core CIM standard as IEC61970 [3] and focuses on transmission system issues. Working Group 14 (WG14) of TC57 maintains a set of standards, named IEC61968 that extends the CIM core to address distribution issues. The majority of the overlap between MultiSpeak and the CIM standards occurs in those extensions maintained by WG14.

At present, both CIM and MultiSpeak provide useful guidance to utilities wishing to implement integrated automation systems, however neither standard is both comprehensive and sufficiently mature to serve all of the needs of the industry. Some utilities may choose to implement integration solely using MultiSpeak where it provides sufficient coverage; typically these have been smaller utilities. Such utilities typically find the MultiSpeak data model and service definitions adequate to support their business processes without the need for significant extensions. For others, a CIM-only approach may be more appropriate. Utilities taking this approach currently must extend the CIM standards to offer a sufficiently detailed data model and also must establish most of their own service definitions. Typically larger utilities are willing to develop this level of extensive customization to meet their business requirements and have the resources available to do so. Some utilities, typically in the middle size range, will integrate some MultiSpeak-compatible and some CIM-compatible applications and are looking to do so with more limited resources than those currently required for a full CIM implementation.

Medium-to-large sized utilities already have begun to inquire if it is possible to leverage the detailed work done by MultiSpeak, but within the context of the international standards offered by CIM. WG14 and MultiSpeak have begun an effort to harmonize their standards to meet this market need. Initially, this has consisted of a joint agreement to review the work of the other group when entering into a new area of development.

To build on this foundation, the two groups have recently agreed to develop standards leading to a mapping that will permit utilities to gain the capabilities of MultiSpeak but using the CIM data model. The proposed standards will be discussed in Section 2 of this paper; one effort at standards harmonization will be discussed in Section 3.

Several utilities have been unable to wait for the standards bodies to harmonize their specifications and have begun integration efforts that borrow from the MultiSpeak data model and service definitions to extend CIM. One such utility integration effort is described in Section 4.

## 2. PROPOSED STANDARDS TO DOCUMENT MULTISPEAK PROFILES USING CIM

In June of 2008 MultiSpeak and WG14 announced an initiative to establish two sets of standards that will lead towards harmonization of their respective specifications. The first set of these joint harmonization standards, when completed, will provide a mapping between the upcoming MultiSpeak Version 4.0 and the upcoming combined release of IEC61970 Version 13 (core CIM) and IEC61968 Version 10 (distribution extensions to CIM). This set of joint harmonization standards will provide guidance to utilities on how MultiSpeak-formatted services and data payloads could be implemented using CIM messages and CIM-formatted data payloads. A side benefit of this mapping effort is that it will permit each standards body to see where the other has implemented functionality and to consider changes in future versions to bring the two standards closer together. The proposed standards to provide a mapping between MultiSpeak and WG14 CIM are summarized in Table 1.

The second set of joint harmonization standards will extend the mapping work outlined in Table 1 by defining a set of detailed guidelines, called profiles, to implement MultiSpeak Version 4.0 capabilities using CIM objects and CIM messaging rules. The proposed profile standards are summarized in Table 2.

**Table 1  
Proposed IEC Standards to Map  
IEC61968 and MultiSpeak® Standards**

Standard	Description
61968-14-1-3	Mapping Between MultiSpeak® V4.0 and 61968-3, Interfaces for Network Operation
61968-14-1-4	Mapping Between MultiSpeak® V4.0 and 61968-4, Interfaces for Records and Asset Management
61968-14-1-5	Mapping Between MultiSpeak® V4.0 and 61968-5, Interfaces for Operational Planning and Optimisation
61968-14-1-6	Mapping Between MultiSpeak® V4.0 and 61968-6, Interfaces for Maintenance and Construction
61968-14-1-7	Mapping Between MultiSpeak® V4.0 and 61968-7, Interfaces for Network Extension Planning
61968-14-1-8	Mapping Between MultiSpeak® V4.0 and 61968-8, Interfaces for Customer Inquiry
61968-14-1-9	Mapping Between MultiSpeak® V4.0 and 61968-9, Interfaces for Meter Reading and Control
61968-14-1-10	Mapping Between MultiSpeak® V4.0 and 61968-10, Interfaces for Systems External To, But Supportive Of, Distribution Management

**Table 2**  
**Proposed IEC Standards to Create a CIM Profile to**  
**Implement MultiSpeak® Functionality**

Standard	Description
61968-14-2-3	CIM Profile for 61968-3, Interfaces for Network Operation, Using MultiSpeak® V4.0
61968-14-2-4	CIM Profile for 61968-4, Interfaces for Records and Asset Management, Using MultiSpeak® V4.0
61968-14-2-5	CIM Profile for 61968-5, Interfaces for Operational Planning and Optimisation, Using MultiSpeak® V4.0
61968-14-2-6	CIM Profile for 61968-6, Interfaces for Maintenance and Construction, Using MultiSpeak® V4.0
61968-14-2-7	CIM Profile for 61968-7, Interfaces for Network Extension Planning, Using MultiSpeak® V4.0
61968-14-2-8	CIM Profile for 61968-8, Interfaces for Customer Inquiry, Using MultiSpeak® V4.0
61968-14-2-9	CIM Profile for 61968-9, Interfaces for Meter Reading and Control, Using MultiSpeak® V4.0
61968-14-2-10	CIM Profile for 61968-10, Interfaces for Systems External To, But Supportive Of, Distribution Management, Using MultiSpeak® V4.0

### 3. INTEGRATION OF THE CIM COMMON POWER SYSTEM MODEL (CPSM) PROFILE INTO MULTISPEAK

MultiSpeak has robustly handled unbalanced distribution power system modeling since its first release in 2001. Transmission systems leading back to an equivalent source could also be modeled in MultiSpeak since its earliest release. Although transmission could be modeled, clearly the emphasis was on the distribution system.

Shortcomings in the MultiSpeak transmission power system model (prior to Version 4.0), included:

- Generation and power production were not modeled in the detail that was needed to map to the CIM CPSM.
- Several equipment types that are required in the CPSM, such as series compensators and static VAR compensators, were not supported explicitly in MultiSpeak.
- MultiSpeak did not support some of the transmission equipment containers (e.g., Bays and Lines) used by the CPSM.

- Values were explicitly expressed in units more appropriate to distribution systems than to transmission area operations (e.g., kW rather than MW; kVAr rather than MVar).

Recently, utilities sought the addition of transmission power system modeling to the already robust distribution system modeling capabilities of MultiSpeak. Simultaneously, the use of the CPSM had grown, particularly among control area operators. This led to the addition of transmission modeling to MultiSpeak in the upcoming Version 4.0 release (V4.0) by the addition of CPSM functionality.

The approach taken in the addition of CPSM capability in MultiSpeak V4.0 was first to look for existing MultiSpeak objects that could carry the content of the CPSM objects. Those objects were enhanced so as to carry all of the fields required to function properly in either a MultiSpeak or CPSM role. Where objects did not exist to carry the CPSM data, those objects were created using CIM names and naming conventions. Objects added to MultiSpeak V4.0 from CPSM were stored in the cpsm namespace in the MultiSpeak schema to enhance the maintainability of the specification as CIM changes over time.

Other changes in MultiSpeak V4 that lead toward enhanced harmonization with CIM include:

- Support for detailed international addresses.
- Support for international telephone numbers.
- Support for all ISO 4217 currency codes [8] as well as a default currency code for messages to reduce data exchange size where appropriate.
- Support for a wide variety of units of measure.
- All values are now expressed in unit/value pairs where the unit to be applied to the accompanying value is definable on a case-by-case basis to reflect local conventions or domain preferences.

WG14 and the MultiSpeak Initiative are now working towards the culmination of this portion of the harmonization effort which will be an interoperability test between MultiSpeak-compatible applications and CPSM-compatible applications in the fall of 2009. This interoperability test will use the then-current MultiSpeak V4.0 release and the combined IEC61970v13 and IEC61968v10 version of CIM planned to be released by year end 2008.

#### 4. INTEGRATION OF CIM AND MULTISPEAK IN THE AMI IMPLEMENTATION AT CONSUMERS ENERGY

The Advanced Metering Infrastructure (AMI) market is relatively immature and technologies are changing rapidly – and will likely continue to change at an accelerating rate. As a means to mitigate technical risks and lower life-cycle costs, Consumers Energy (CE) is actively involved and making significant contributions to industry standardization efforts impacting their AMI program. CE is not only performing thorough assessments of key technologies, but is considering how each technology and the data fit into the overall integration infrastructure – from interfacing with the Home Area Network (HAN) through to the Meter Data Unification System (MDUS) and then through to the applications supporting business processes. To achieve economies of scale, this data exchange must be based on industry standards that are adequate and supported in the market place.

In reference to Figure 1, through the Service Definitions Team of the AMI-Enterprise Task Force [10], Consumers is leading an effort to examine the CIM and MultiSpeak standards, determine gaps, and make recommendations back to both MultiSpeak and the IEC. As this work is being done in collaboration with utilities and vendors and being tested as part of their AMI program for implementation, artifacts stemming from this team will be of high quality and invaluable in the development of the aforementioned IEC 61968-14 series of standards. Consequently, these IEC standards will already be building substantial momentum while they are still in a draft state.

The process employed by Consumers Energy is to review the content of both the IEC CIM (current draft), and MultiSpeak version 3. MultiSpeak version 4 will be reviewed for the next iteration of the application integration effort once it had been completed. The content review includes the information objects, sequence diagrams, or any services that have been defined in either standard. To identify application integration requirements the team starts with use cases that document the related AMI business processes. Integration requirements are identified where information objects are based from system to system, for example, if information is passed from a Customer Information System (CIS), to a meter data management system. The team has developed a service naming approach that uses a CIM-based verb, then an information object, followed by the pattern name. For example, ChangeMeterSystem\_Send, (see figure). The team is then building out a matrix that lists components such as service, source and destination system, and information objects. The team will then build out the content of each information object by reviewing CIM, MultiSpeak, or other vendor sources that have agreed to share information. It is expected that this work will result in a consistent interface, with consistent service definition, and facilitate the capability of systems to interoperate.

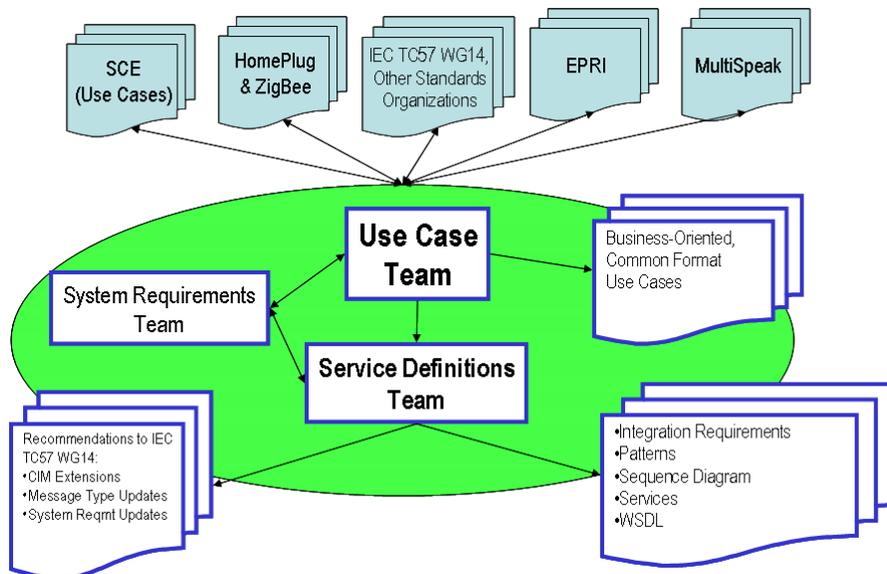
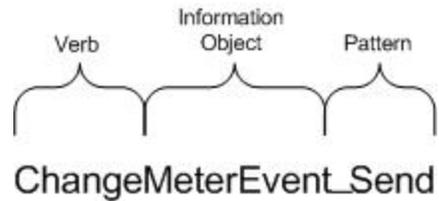


Figure 1: AMI-Enterprise Task Force Overview

## 5. CONCLUSIONS

MultiSpeak and the CIM are both being used on an increasing basis by utilities and their vendors for inter-application integration. But participants in this market space would rather not have two similar and evolving standards because it adds to their costs to understand, keep up with, and support both. This paper has provided an overview of the work now underway to bring these two popular standards together. As users will no longer need to fear “betting on the wrong horse” and as the quality of these standards continues to improve through collaboration, the authors believe this harmonization effort will break up a significant “log jam” that has been hindering utilities and their vendors in implementing standards-based integration solutions. The authors want to take this opportunity to encourage feedback and participation in this process by any interested parties.

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## Biography

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**Greg 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.

## Gerald R. Gray

Mr. Gray is an enterprise architect with Consumers Energy, a combination electric and gas utility serving over two

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# KPIs in Your Pocket: Leveraging Mobile Technologies for Improved System Demand Initiatives

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**Keywords:** Key Performance Indicators, demand response, operations intelligence, KPIs, outage management.

## Abstract

Utilities are faced with many challenges – visibility into the network, manual processes, lack of integration between multiple data systems – which leads to poor reaction time and less than perfect decisions. But that doesn't have to be the case. By leveraging existing infrastructure and extending the use of familiar devices (e.g. your cell phone or PDA of choice), knowledge workers can align role-based metrics with business objectives to drive productivity and reduce costs, helping utilities to optimize capacity and asset utilization.

This paper will discuss how utilities can extend the value of their existing investments to improve visibility into utility operations, including the ability to:

- deliver consistent data access via desktops, laptops and mobile devices to improve decision making and enhance system reliability initiatives;
- increase cross-departmental collaboration;
- improve analytics for optimized capacity and asset utilization;
- simplify user adoption of mobile technology for tracking SAIDI/CAIDI reliability indices and real-time trending.

We will also detail a case study from Western Power, an electricity networks corporation in Western Australia distributing power along 88,000+ miles of transmission lines. By arming hundreds of employees with role-based, real-time operational data via mobile devices and traditional web displays, Western Power augmented their “Summer Ready” demand response program.

## 1. INTRODUCTION

With the continued evolution of the grid comes the increased need for on-demand, reliable metrics. Utilities are faced with many challenges that hinder decision making. This includes lack of visibility into the entire network,

manual processes that still dominate day to day processes, complex business rules, varied IT assets and lack of integration between multiple data systems.

### 1.1 The Grid Today

With the continued increase in the complexity of the grid, these issues will only get worse.

Today, decision makers have less than optimal reactions to outages and are not armed with the right data to make decisions quickly and accurately. This results from a combination of factors, including:

- Lack of visibility on the edges of the network;
- Poor coverage and information access at distribution areas; and
- Reliance on manual data and displays.

The combination of new technology and new attitudes towards conducting daily operations fits in with the changes that the intelligent grid will bring. Better communications networks, an increased number of sensors, improved analytics and the spread of enterprise mobility initiatives will allow real-time pricing, faster and smarter decision making and more sophisticated demand response programs.

Utilities need to take a look at their current technology infrastructure and daily operations in order to tackle today's challenges and prepare for tomorrow's opportunity.

### 1.2 The Challenge of Integrating Data Systems

The lack of integration between data systems – such as EMS, DMS, OMS, SCADA, GIS – continues to pose significant problems, confining important data in silos and propagating an atmosphere of information overload. With more initiatives to create a smarter grid also comes the inherent increase in additional technology systems.

But technology alone is not going to solve the problem. Only through a comprehensive, top-down *and* bottom-up strategy can utilities improve demand response programs.

This starts at the core of the information ecosystem: with Key Performance Indicators.

### 1.3 Key Performance Indicators (KPIs)

At no time has it been more important to understand your asset, its performance, and how to optimize it given the market drivers at play. However, it can be challenging to optimize these assets with the lack of visibility of real-time KPIs.

Optimization is not an end of the month process that corrects for problems noticed after they've occurred. To truly optimize your assets, you need make "in the moment" fact-based decisions by taking advantage of on-demand metrics which can be created from existing operational data sources.

KPIs can be the foundation for efficient and reliable electric systems, but too often they are misunderstood, inconsistent, or even hidden from the people who need them most.

The following are important forces at play in today's utilities, all of which underscore the importance of on-demand KPIs as the foundation for an efficient and reliable electric system.

- 1 The drive towards consistent behavior – if KPIs are consistent up and down the roles of the organization, and across departments, then transparency is seamless from the field to the engineering office.
- 2 Enterprise mobility – with an increase in the use of mobile phones and PDAs out in the field, utilities need to get the information out...quickly, and to the device of choice of each decision maker. With on-demand data, decisions can be based on real-time information rather than gut instinct.
- 3 Improved outage response – mobile data dispatch results in more crews on more jobs, more often. Therefore, supplying those crews with accurate, dependable, real-time asset data allows field personnel to cross-check control room instructions with the situation in the field.
- 4 Improved operator safety – the more data that can be infused into the field crew's decision making process, the safer that crew will be, as decisions are made in the power restoration process.

### 1.4 Asset Optimization

One of the most challenging scenarios to optimization of an organization's assets is the ability to effectively

communicate across various business units within that organization. After all, primary functions such as generation operations, scheduling, trading, operations and maintenance, and environmental compliance are usually not the responsibility of the same business unit.

The key to optimization is to make sure it becomes part of the everyday experience. By delivering clear, concise information to the right person at the right time, being knowledgeable and taking action become somewhat of a subconscious response.

How many people do you pass every day instantaneously reading and responding to their email on their Smart Phones or Blackberries? How many did you pass doing that very thing five years ago? Our culture thrives on constant awareness and connectivity, and so does your business.

To most organizations, people are every bit as important of an asset as a turbine. So it is important to optimize their time, allowing them to spend more time focused on the most valuable tasks.

## 2. DATA AND GRID VISIBILITY

In the effort to evolve the grid to the level of being "smart enough" to predict and adjust to network changes, we need to have a better understanding of how to deliver appropriate data to decision makers, whether they're sitting in an office or they're hundreds of miles offsite.

We need to not only rely on manual processes and gut instinct decision making. Instead, we need on-demand data accessible wherever, whenever.

The following guidelines will help utilities gain visibility into the grid, improving overall decision making and fostering sophisticated demand response programs.

### 2.1 Extend Value of Existing Technology Investments

Now is *not* a time to be adding line items to your budget! Instead, take a look at the systems you already have in place – OSIsoft PI System, SmartSignal, Oracle or other SCADA backend SQL systems – and determine how these can be leveraged, for equipment rating, asset or network performance data.

Additionally, with the advancement of communications networks, utilities will be able to gather and distribute more information and link different elements of the organization – from knowledge workers to IT assets, from partners to customers.

### 2.2 Agree on Key Metrics

Once the data systems have been inventoried, agree on key metrics – by department, by business unit and across the organization.

Key metrics are usually common across the industry. Typical examples would include highly sensitive cost inputs to the business, such as the burning of oil for generation, as well as politically sensitive metrics, such as emissions, or the amount of “green” generation. Also, standard industry measures for customer service in the form of CAIDI and SAIDI are typically reported as key business drivers.

### **2.3 Keep New Technology Simple and User Friendly**

The biggest mistake you can make is giving operations guys technology they *don't* need! Clutter can kill projects.

With this in mind, be sure to leverage the technology (e.g. data historians) and devices (cell phone or PDA of choice) that knowledge workers are familiar with.

For example, by delivering the Officer In Charge (field-crew-chief) with real-time, role-based information about DPA periodic studies, you are arming decision makers with useful, relevant data to help them do their job better... rather than overwhelming them with extra information that only adds a burdensome step (a pitfall many organizations face.)

### **2.4 Ensure Data Consistency**

At the heart of improved system reliability initiatives is data consistency. The crew chief may not use the DPA real-time study for every restoration job, but the data is available any time he needs it, especially if he is in doubt as to the control room's instructions in relation to the rating of an asset.

Just as important is that the field crew can cross check control room instructions against predicted asset performance to see what the control room sees. Field and control room staff can view the same data, at the same time – so that both parties are satisfied as to the safety and integrity of a power restoration plan.

Data needs to be presented on demand, in a timely manner, without intrusion to the work process. This requires a highly automated system to preserve integrity and ensure reliability. Faster, better access to data is the answer to those scenarios we face every day, for example delivering remote power when a transformer fails.

### **2.5 Promote Collaboration**

Information silos are a real threat to effective operations. Without collaboration across departments, utilities not only

lose the benefit of captured knowledge of an organization, but they end up operating blindly on a day to day basis, without sufficient insight into the rest of the organization.

Take, for example, Smart Grid or greenhouse emission reduction efforts. As these initiatives continue to get implemented – and mandated – utilities will need more visibility into data and more collaboration than ever before in order to orchestrate successful development across department, and beyond traditional utility boundaries.

### **2.6 Extend Operations Intelligence to Reliability Indexes**

In order to effectively track reliability indexes such as SAIDI and CAIDI and create real-time trends, you need a simplified view of all relevant metrics.

With an on-demand dashboard of KPIs, decision makers throughout the organization can improve demand response to customer and fault outages and ensure accurate tracking of duration measurements.

### **2.7 Align Operations with Business**

Aligning daily operational metrics with business objectives can seem like a daunting task. However, with consistent, on-demand KPIs and an organization-wide drive towards efficient decision making, utilities can – and will – get there.

It's all about the bottom line, which will be positively impacted with the right combination of technology and process changes, ensuring that utilities drive innovation, while improving productivity and reducing costs.

## **3. CASE STUDY**

In January 2008, Western Australia's customers were at risk of not having power because the main (and only) gas supply line from the northwest of Western Australia to Perth City was interrupted by a fault in a switchboard that controlled the gas supply into the pipeline. Being peak load time for Australia summer, the state had just come off the back of several 105+ degree Fahrenheit days in a row and another hot day was predicted.

### **3.1 Summer Ready Demand Response Program**

Western Power, an electricity networks corporation in Western Australia distributing power along more than 88,000 miles of transmission lines, had several strategies in place to handle fuel and demand, and to integrate on-demand operations intelligence software within their “Summer Ready” demand response program.

These strategies included:

- 1) Public awareness
- 2) Fuel substitution
- 3) Operations intelligence software

### 3.2 Role of Operations Intelligence in Demand Response

Over the course of the last year – and in an effort towards continued productivity improvements and the ever-important cost savings – Western Power armed hundreds of their employees with role-based, real-time operational data via mobile devices and traditional web displays.

Everyone from frontline SCADA support staff, system controllers, operations engineers and managers now have access to accurate operational information, pulled from multiple data sources, exactly when and where they need it, which more often than not, is out in the field.

### 3.3. Example KPIs

As discussed earlier, the baseline for reliability improvements is found at the core of the information: the KPIs themselves.

In Western Power’s case, the following on-demand KPIs were used in their demand response, asset management and enterprise mobility initiatives:

- real-time trending of System Total Megawatts;
- operational SCADA Master Station availability;
- real-time trending for monitoring asset performance against limits;
- real-time alerting for monitoring generation fuel mix and contribution of wind generation to system total generation.

### 3.4 Lessons Learned

Possibly what’s equally important to what Western Power did do, was what the utility did *not* do – information rarely shared, but oftentimes more useful in helping to determine long term and future strategy.

While many had identified how operations intelligence software could have huge impact on Western Power’s customer experience, both internally and externally, it had not yet been applied to mitigating a generation shortage.

Lesson learned?

In the midst of a crisis is not the time to determine your enterprise operational data provisioning strategy. In order to serve the organizational or public awareness need for information, the strategy that connects coal face data collection with information consumers must already be firmly in place prior to demand for that information.

In the future, Western Power plans to extend the use of on-demand KPIs to initiatives such as public web displays of system demand with operational capacity limit. In the interests of transparency, Western Power plans to make operational information continuously available, regardless of demand due to a crisis.

## 4. CONCLUSION

Have you ever wondered why certain applications on certain machines respond slowly? How well is the interface between your turbine control system and other back end systems such as your DCS or historian performing? Are you seeing the same value repeated over and over again yet you are sure the value has changed?

These questions – along with hundreds more that you’re facing on a daily basis – can all be identified and addressed with consistent metrics and simple KPIs.

### 4.1 Next Steps

In order to start down this path of improving visibility into data, utilities should:

- 1) Recognize the value (statesmanship) of data sharing without compromising operational decision making. Share metrics and totals – not individual asset attributes.
- 2) Determine the benefit that could be extracted from combining information from disparate data sources, e.g. a DCS with a ratings system.
- 3) Identify operational issues that may lurk in data historians, unrecognized (because the attributes haven’t been rolled up as part of a bigger picture.)

## **Biography**

**Michael Saucier, CEO**

**Transpara Corp. ([www.transpara.com](http://www.transpara.com))**

Mr. Saucier has more than 20 years experience leading innovation in the utility and process industries. Before Transpara, he served as vice president of worldwide marketing and business development for OSISOFT ([www.osisoft.com](http://www.osisoft.com)). His experience with global customers in the utilities markets served as the catalyst for the development of Transpara as a company that extends performance management tool into a mobile environment.

Previously, he founded Sequencia Corporation, which became the market leader in innovative batch process manufacturing software. Under his leadership, Sequencia created OpenBatch, the first factory automation system delivered on the Microsoft Windows NT operating system. The process software portion of the business was sold to Rockwell Automation in 1999.

Earlier in his career, Mr. Saucier held positions at Honeywell and ABB as senior principal application consultant and senior control engineer, respectively.

Mr. Saucier received his M.S. and B.S. degrees in Chemical Engineering and a B.S degree in Chemistry from the University of California, Santa Barbara, graduating with highest honors. His master's thesis used applied mathematics to describe and predict onset of instability in multivariable process control systems.

# Achieving Smart Grid Interoperability through Collaboration

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## Abstract

Numerous analyses, including the “Prism” analysis at the Electric Power Research Institute (EPRI), show that energy conservation and distributed resource integration are critical elements of an overall strategy to reduce carbon emissions. The smart grid is the enabling infrastructure that makes much higher levels of distributed resource integration possible. The value is maximized by leveraging Distributed Resources at both the local and overall system level as a “virtual power plant” to better match energy supply with demand along with related value-added benefits.

Due to the complexity, number and scale of the systems and devices involved in creating a demand-side virtual power plant, interoperability between the various systems is the key to success. An interoperable smart grid fosters increased competition among suppliers, innovation, choice, reduced costs and reduced capital risk caused by technology or vendor obsolescence, and enables automation resulting in increased value and improved reliability.

Unfortunately, interoperability cannot realistically be achieved by a single entity and requires collaboration from numerous organizations including utilities, regulatory bodies, standards bodies, vendors and more. An approach of structured regional utility demonstrations designed to promote and evaluate integration of distributed resources at all levels of power system operations will further smart grid interoperability. Utilizing a standardized approach like the IntelliGrid® methodology to develop use cases and standard functional requirements can further communication, information, and control infrastructures required to support integration of emerging technologies as well as identify critical gaps in existing standards providing focus for future research and development.

## 1. A COMMON UNDERSTANDING

To start with, we need to have a common understanding of what is the smart grid, its value, what are the technology drivers of a smart grid and underlying assumptions. There is little argument regarding the level of hype related to smart

grid. On Gartner’s hype cycle [1] (figure 1), one could argue the smart grid is at the “Peak of Inflated Expectations.”

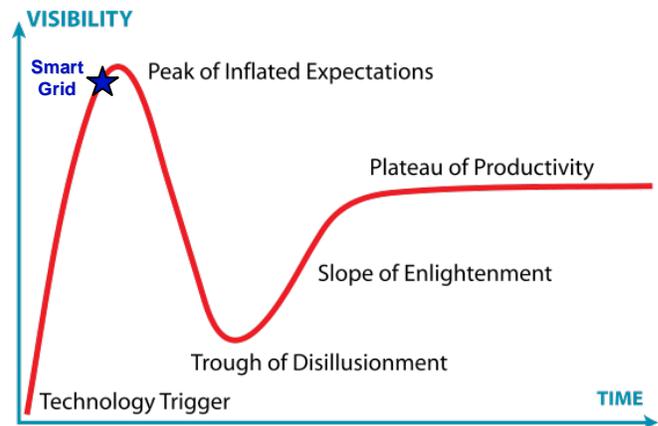


Figure 1: Gartner’s Hype Cycle [1]

It is important that we minimize the time in the “Trough of Disillusionment” and one way to do that is to manage expectations by understanding the true capabilities of a smart grid. Electric utilities around the world realize the opportunity and are already investing in the communication and information infrastructure that is expected to be the backbone of a smart grid. Deploying collaborative smart grid demonstration projects that uncover gaps in standards and open communications related to integration of distributed resources will get the smart grid on the “Slope of Enlightenment” sooner. Investors and regulators want to know if the investments will be a technical and financial success. Customers want to understand if benefits will justify the costs that may ultimately be borne by them. Carefully structured demonstrations will result in a common understanding of benefits and practical applications of a smart grid. As the benefits of real demonstrations become accepted and the technology and related standards becomes increasingly stable, the smart grid will reach the “Plateau of Productivity.”

### 1.1. What is the smart grid?

The smart grid has numerous definitions with a very broad scope. It’s interesting to ask the question and see the responses you get because it varies significantly based on

the field of expertise of the person asked. A smart grid is one that incorporates information and communications technology into every aspect of electricity generation, delivery and consumption in order to: minimize environmental impact; enhance markets; improve service; reduce costs and improve efficiency. This definition is basically about leveraging gains in the convergence of communication, computer hardware, and software technologies adding intelligence to the electric power industry infrastructure. This is the normal evolutionary path of technology development that has occurred in other industries such as telecom, industrial process control system development, and the entertainment media industry. This technology evolution applies to the electric power industry in the same manner and is referred to as the smart grid.

### 1.2. A Smart grid can reduce carbon emissions

One significant goal of smart grid demonstrations is to accelerate reduction of CO<sub>2</sub> emissions. First-order estimates of energy savings and CO<sub>2</sub> emissions impact is 56-203 billion kWh and 60 to 211 million metric tons of CO<sub>2</sub> per year in 2030[2]. Five key applications enabled by a smart grid provide this impact: 1) Continuous commissioning for commercial buildings; 2) Distribution voltage control; 3) Enhanced demand response and load control; 4) Direct feedback on energy usage; and 5) Enhanced energy efficiency program measurement and verification capabilities.

### 1.3. Integration of distributed resources

The most significant projected reduction on CO<sub>2</sub> emissions from a smart grid will result from developments associated with integration of distributed resources along with direct feedback on energy usage and market conditions. Distributed resources include demand response, distributed generation, storage, and renewable generation. It is estimated that these resources alone will make up 80% of the projected 60 to 211 million metric tons of CO<sub>2</sub> reduction per year in 2030[2]. Although distributed resources are being deployed today, they are not transparently integrated at the system operator level and not enough is being done to further interoperability. Today, advances in emerging computing hardware, software and communication technologies are making integration more cost effective than ever before. Efforts focused on integration of distributed resources will provide the most significant value for CO<sub>2</sub> reduction related to smart grid deployments.

### 1.4. Smart grid technology drivers

The Virtual Power Plant (VPP) (figure 2) is a relatively simple concept; aggregating multiple distributed resources that collectively can respond similar to a generator to form a VPP. The technology capabilities for a VPP exist today but they have not been integrated to make distributed resources

part of the operation of the power system. The VPP concept is a particularly attractive way to demonstrate smart grid functionality because it touches on all aspects of a smart grid – communications infrastructure that goes all the way to the consumer and into the consumer premises, interfaces with advanced metering, distribution automation, energy management systems and optimization of system performance through a combination of enterprise level applications and distributed intelligence.



Figure 2: Virtual Power Plant (VPP)

Significant developments in communication, hardware and software technologies are enabling distributed intelligence to be embedded at the device level at a low-cost. As an example of technology advances, in 2006, the Wi-Fi semiconductor market shipped just under 200 million Wi-Fi chipsets, and reached over 500 million chipset shipments cumulatively. Research indicates that around the middle of 2008, the industry will have passed the one billion mark for cumulative chipset shipments. Even more impressive is the projection that there will be well over a billion chipsets shipped in 2012 alone, with cellular handsets and consumer electronics accounting for over two-thirds of that total [3]. This example of technology evolution is amazing. If this capability is applied to the smart grid, it is equivalent to nearly a billion devices per year capable of performing smart grid functions by 2012. A related impact on our industry is the evolution and growth of ultra low-power Wi-Fi now competing with ZigBee®. ZigBee has seen some recent successes in Advanced Metering Infrastructure (AMI) deployments, but lacks third party product availability unlike Wi-Fi.

Another recent news announcement was that Atmel, Cisco and the Swedish Institute of Computer Science developed an open source IPv6-Ready protocol stack. The small memory footprint of the stack, <13KB, promises to Internet enable virtually any device regardless of power or memory limitations [4].

Computing technology advancements coupled with an explosion in low-cost communication penetration are factors driving the capabilities of a smart grid. Here are some headlines regarding communication trends:

- Broadband to reach 77% of U.S. households by 2012, Gartner says [5].
- FCC Chairman Kevin Martin wants broadband across the USA and proposes “Free Broadband” as a condition to sale of the wireless spectrum stating that it is important to the welfare of U.S. Consumers and a social obligation [6].

Those headlines are related to public communication infrastructure, but there is similar growth in private communication infrastructure deployments in the utility industry related to AMI and system automation. AMI can be described as automated two-way communications between utility meters and the utility. Data from AMI systems is an enabler for additional services, but the data needs to be accessible in a common format. Unfortunately today, AMI system communications are not standardized from the meter to the enterprise, resulting in vendor lock-in or limited capabilities since systems can’t readily access the data.

Utility industry communication standards development is not keeping up with technology advancements. With standards processes taking years to evolve in a technology environment where communication bandwidth and computing power are doubling every 18-24 months (Moore’s law), creative methods must be used to further the standards development that will result in interoperability sooner rather than later.

## 2. THE NEED FOR INTEROPERABILITY

It is important that diverse devices and systems playing in a smart grid game achieve the ability to inter-operate. Although dynamic rates and systems are deployed across the country and world today to perform functions of a smart grid related to distributed resource integration, nearly every program has a different format for communicating prices and events. Without a standard format for communicating information, it is costly to develop products and services that function in every market. In addition, one cannot build products and services that function in this environment without knowing the regional energy market in which they will be deployed.

The significant challenge for successful deployment of a smart grid related to distributed resource integration is implementation of common standards. Agreed upon standards will unleash the free market to further develop innovative products and services that enable interoperability at all levels of power systems. In addition, to be truly effective, the grid must also be prepared to interact with standards from other industries, such as industrial

equipment, building and process control systems, home automation, appliances, and plug-in hybrid vehicles (PHEV).

Until there is transparent communication interoperability from distributed resources to utilities and within utility systems, there will be significant risk when considering investing in non-standardized systems. This lack of interoperability is one of the primary factors holding back utilities from deploying systems and third parties from furthering the development of controllable system interfaces and devices.

### 2.1. The integration weak link

Where is the weak link in integration of distributed resources? There are numerous weak links and a lot of stakeholders. Standards are progressing and there are significant ongoing efforts to further those standards, but there still isn’t complete industry consensus resulting in uncertainty in smart grid and related AMI technology deployments. At a high-level, there should be agreed upon standards for presenting meter data to the utility AMI system. There is hope that the American National Standards Institute (ANSI) standards will provide part of the answer for communication between the meter and utility systems over an AMI network that is not dependent on the communication media. This could be part of the solution, but there are still integration issues when presenting data from the AMI system to the enterprise or meter data management system (MDMS). Common Information Models (CIM) such as those in IEC 61970 and IEC 61968 can be further developed extending to additional utility systems and processes.

Other standards for communicating in the home are competing. Recently, ZigBee® and HomePlug® announced an alliance to create a wired HAN standard [7]. This alliance demonstrates the interest among organizations to come to an understanding to reach a common goal, but controversy continues. Less than a month after the ZigBee, HomePlug announcement, the IP for Smart Objects (IPSO) Alliance announced the “New Industry Alliances Promotes Use of IP in Networks of ‘Smart Objects’.” [8] The IPSO alliance has a goal of promoting Internet Protocol (IP) as the network technology best suited for connecting and delivering information to devices. Ideally, standards will be developed that are media agnostic, but there are clearly differing views and no clear cut winner creating uncertainty and risk when considering investments in these systems.

These are just a few examples of how integration standards need to mature to ensure interoperability but there are many more areas of integration weaknesses at the enterprise level. For the integration of distributed resources, AMI data should be usable across the enterprise including Distribution Management Systems (DMS), system planning and real-

time integration with system operations. Distributed resources need to be able to communicate information necessary to be treated on the same plane as generation. A collaborative effort pulling stakeholders together can facilitate communication to assemble seemingly competing solutions that ultimately have the same end-state and goals in mind.

### **3. THE POWER OF COLLABORATION**

The well-known adage, the whole is greater than the sum of its parts, acknowledges the power of collaboration. Uniting utilities, research organizations, regulatory bodies, and standards bodies strengthens positions and solves common problems more effectively. Issues associated with integration of distributed resources are common among nearly all electric utilities.

Achieving all the benefits of a smart grid will not be easy. The task is very complex and furthering standards alone will not get the job done. The scope is global and thousands of companies and organizations working together are necessary to achieve a smart grid. By collaborating to further standards as well as identify critical gaps in standards and technologies, the collaborative becomes a powerful force that will result in a market that fosters a capitalistic environment with a long-term goal of system wide interoperability.

#### **3.1. Stakeholders**

The stakeholders with a vested interest in the success of a smart grid are wide ranging. It includes utilities, consumers, users groups, policy makers and vendors. The list is large and growing, also including EPRI, the Department of Energy (DOE), NETL Modern Grid Strategy, State Regulators, NYSERDA, PIER, LBNL, PNNL, DRRC, DRCC, SAP AMI Lighthouse Council, The Galvin Initiative, European Smart Grid Initiative, GridWise™ Alliance, UCA International User's Group, IEC, IEEE, IEN, AHAM, NIST, NEMA, SAE, ANSI, NAESB, FREEDM, ZigBee® Alliance, IP for Smart Objects Alliance, HomePlug® Powerline Alliance, Insteon® Alliance, CableLabs®, OBIX™ and more. We apologize for all the acronyms, but the point of this list is to demonstrate the enormous amount of activity around the nation and world to further a smart grid.

Believe it or not, vendors are not the enemy and many of the listed organizations are representing vendors and manufacturers. In most cases, vendors want standards as much as the utility industry and consumers. The lack of standards forces vendors to develop bridge-the-gap solutions systems that perform the functions necessary for integration of new and legacy systems.

Until standards exist and are demanded by consumers, vendors will continue to develop closed or proprietary

systems that provide the competitive advantage necessary for today's market conditions. They understand customer resistance to vendor lock-in and it doesn't make good business sense for vendors to force it.

All stakeholders must be involved in a collaborative effort to provide a well-rounded view of the wide-ranging impacts of the smart grid. Regulatory policies vary widely and systems must be designed to accommodate this broad range of requirements. Standards bodies have a long-term view and technology development is advancing rapidly. Standards development must evolve more rapidly to minimize the amount of non-standard deployments in the industry. Utilities understand the assumed value of what a smart grid can bring to their shareholders and ratepayers. Demonstrations must test assumptions to bring more certainty to the business case and the value must be transferred to consumers.

#### **3.2. The value of a collaborative demonstration**

Utilities are investing in smart grid solutions today, but those solutions, individually, are not furthering the industry. From a functional perspective, today's smart grid deployments perform as specified, but additional effort is required to further interoperability outside of the utilities direct needs to gain additional societal benefits. By joining a collaborative effort, additional resources can be applied to projects that lay a foundation and can further industry development of the interoperable smart grid. Collaboration encourages the sharing of human knowledge and saves countless hours of labor in research, studies, evaluation and software development. In addition, the result of having standards for system integration lays a foundation for opportunities such as the development of open source software. In fact, a collaborative effort should not ignore an opportunity to develop open source software for market and system integration.

The book Wikinomics: How Mass Collaboration Changes everything [9], describes the opportunity at hand. The concept of mass collaboration is about harnessing the collective capability and genius to spur innovation, growth, and success. Although Wikinomics has perhaps an overly optimistic viewpoint, it does outline a good general overview of the opportunity at hand with advancing a smart grid with collaboration.

#### **3.3. Business issues and opportunities arising from collaborative demonstrations**

Several business issues arise from collaborative demonstrations. Poor project management can result in chaos and a slow-down in productivity. With the number of stakeholders involved, decisions will be made by consensus as well as by monitoring the results of successful technology deployments. The collaborative needs to be

Careful of dissention or taking sides that can result in situations similar to a two-format landscape such as BETA vs. VHS or HD DVD vs. Blu-ray. A controversial landscape will keep technology and integration from reaching mass adoption.

The opportunities related to benefits of a smart grid are significant. It is estimated that for a net investment of \$165 billion, the total value estimate range of \$638 - \$802 billion resulting in a benefit-to-cost ration range of 4:1 to 5:1 [10].

	<b>20 year total</b>
<b>Net Investment Required</b>	\$165 Billion
<b>Net Benefit</b>	\$638 - \$802 Billion
<b>Benefit-to-Cost Ratio</b>	4:1 – 5:1

Table 1 [9]

It must also be understood that there will be a significant period of time before full interoperability can be realized. Utility systems and even appliances have a long life span ranging from years to decades. It will be important to evaluate bridge-the-gap integration solutions to maximize the lifetime of existing legacy systems so they survive their intended lifespan. A significant portion of a smart grid demonstration initiative should be focused on identifying this reality and understanding how to best manage it.

#### 4. DEVELOP A SOLID FOUNDATION

It is important to have a solid foundation on analytical integration approaches when understanding the impact of distributed resources as it applies to a smart grid. It is equally important to understand critical technologies and systems that are instrumental in achieving widespread integration of distributed resources. An approach developing an analytical framework and architecture reference design for integration of technologies and systems should be used as the foundation to evaluate multiple collaborative demonstrations equally.

The foundation should support demonstration design, implementation, and application of key integration technologies. The IntelliGrid® architecture should be applied to develop use cases and specify highest priority requirements for communication and control of distributed resources. For each demonstration project implemented, a combination of performance, security, benefits, and/or interoperability assessments must be conducted based on data collected through lab and field deployments and communicated to stakeholders.

##### 4.1. Analytical framework and tools

Analytics provide a structured framework for characterizing the integration issues to be addressed and guiding principles for scoping regional demonstrations. A framework should

include a wide range of demonstration tasks and objectives. Objectives may include environmental and economic impact, system reliability, power quality, system security, and other goals for applying distributed resources. Demonstration objectives should be mapped to a common integration framework. The framework should track the extent that the existing demonstrations address integration barriers, and reveal critical gaps that may be addressed through the design of future demonstrations. Tasks must include review of work by standards bodies, regional system operators, vendor products, technology assessments, and CO<sub>2</sub> emission calculation methods. An assessment of how distributed resources impact forecasting and network planning and operation should also be considered.

The objective is to establish the set of analyses required to resolve the established barriers and to provide credible data and a consistent set of methods and processes to aid decision making in several critical areas. These areas include: distributed resources as a factor in planning and operations, integration approaches, quantifying the firmness of these resources that can be coordinated to support grid and market operations, and their potential impact in mitigating green house gas emissions. The analyses should include a broad mix of distributed resource applications, from merely sending information signals that coordinate voluntary demand response to dispatching energy storage and distributed generation for system reliability. The scope should also include investigation on enhancing customer choice through electric service innovations, as in the application of microgrids to support the supply system and to deliver quality power and reliability at customer-preferred levels.

##### 4.2. Critical Integration Technologies and Systems

Examples of critical integration technologies include common information model, local controller, communications interfaces and protocols. Identifying and influencing the design and deployment of technologies are instrumental in achieving widespread integration of distributed resources. Project efforts should include developing common information models for distributed resources, system interfaces, and local controllers. These efforts will be designed to identify critical gaps in market and system protocols and develop workable methods that can be demonstrated to address the identified gaps. System-level technologies to be investigated include system controls interfaces (e.g., for integration with distribution management systems), new system topologies (e.g. microgrids), and communications infrastructures that integrate distributed resources with market management systems.

### 4.3. Communication and technology transfer process

Technology Transfer provides stakeholders timely and useful interpretations of the results and syntheses of lessons learned across all demonstrations. It is important to frequently communicate the status of field demonstrations, lessons learned, architectural challenges, issues impacting standards, and common interest areas to explore further. The goal is to inform and coordinate with standards bodies, regulators, and industry at large on critical issues towards overcoming challenges in distributed resource integration. The electric power industry must be engaged in influencing the development of communications interface standards for distributed resources to support utility and consumer energy management needs.

## 5. KEY DEMONSTRATION ACTIVITIES

Demonstration activities must be challenging enough to test existing distributed resource integration standards and interfaces while also able to identify gaps and weaknesses. The demonstrations must test business case assumptions and communicate the results to stakeholders. The collaborative demonstrations must employ the analytical and technical framework designed as the foundation for achieving smart grid interoperability

### 5.1. Multiple demonstrations

Multiple regional demonstrations can effectively accomplish overall collaborative goals if each demonstration integrates multiple levels of integration of multiple types of resources. No single demonstration can cost effectively accomplish the goals, but having an aggregate of demonstrations in diverse geographical regions and in varying power system infrastructures provides an overall picture of the state of the smart grid.

### 5.2. Leverage existing and planned investments

To minimize financial risk, demonstrations should leverage existing and planned utility projects related to integration of distributed resources. There are a sufficient number of national and international smart grid-type deployments that can be leveraged without having to devise custom demonstration projects. The scope of existing and planned utility smart grid projects must be expanded to include foundational analytical and integration framework and architecture to accomplish overall goals of the collaborative demonstration initiative.

A five year term of this initiative should be sufficient to test existing and emerging technologies and systems to increase the learning and define the overall industry needs for system-wide integration. This will build a consensus on the approaches that work best while outlining needs for future demonstration needs to further interoperability.

### 5.3. Multiple levels of integration, multiple types of resources

By deploying multiple demonstration projects that have varying levels of integration of multiple distributed resources it collectively results in data that otherwise is not achievable. Integration deployments should test systems including the Home Area Network (HAN), AMI, Distribution Management System (DMS), Supervisory Control and Data Acquisition (SCADA), System Operations and Planning, Markets, as well as the numerous utility Enterprise systems.

Multiple types of distributed resources (demand-response, storage, distributed generation and renewable generation) should be integrated transparently so they have visibility at the system operator and market in the same manner as generation resources effectively creating a VPP.

## 6. NEXT STEPS

Stakeholders interested in furthering smart grid interoperability are encouraged to collaborate with leading organizations with common goals. EPRI is collaborating with the numerous stakeholders in a smart grid demonstration initiative along with DOE and European Smart Grid demonstrations. By having strong stakeholder relationships that are collaboratively working towards a common goal, we can more rapidly provide a foundation for widespread adoption of a smart grid that provides real value.

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## **Biography**

**Matthew P. Wakefield** – Mr. Wakefield is a Senior Project Manager at the Electric Power Research Institute (EPRI) managing EPRI’s smart grid demonstration initiative. He has over 22 years of energy industry experience and prior to joining EPRI, was the Manager of Applied Technology for Integrys Energy Group focused on developing and applying information and communication technologies related to real-time energy information transfer between control centers, generators, markets and consumers. This team developed a number of innovative solutions including DENet® and eMiner® that utilized open source software and low-cost embedded hardware while leveraging customer owned Internet communications for smart grid applications in both regulated and deregulated energy markets. He received his BS degree in Technology Management from the University of Maryland University College.

**Mark McGranaghan** – Mr McGranaghan is a Director in the EPRI Power Delivery and Utilization (PDU) Sector. His research area responsibilities include overhead and underground distribution, advanced distribution automation, Intelligrid®, and power quality. Research priorities include developing the technologies, application guidelines, interoperability approaches, and standards for implementing the smart grid infrastructure that will be the basis of automation, higher efficiency, improved reliability, and integration of distributed resources and demand response. He is also directing EPRI’s extensive smart grid demonstration initiative (5 year effort) to help coordinate the industry approach for distributed resource integration with the operation of the grid.

# Sustainable Energy Portfolio Management in Support of the Smart Grid Concept

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**Keywords:** Sustainable Energy, “Smart Grid”, Policy and Regulation

## Abstract

In the recent years, there has been a rapidly growing interest in what is called "Smart Grid – Digitized Grid – Grid of the Future". The main drivers behind this market trend and evolving business environment are customer, grid performance, improved environment, productivity improvement and stakeholders' attention. The main vision behind this market trend is the use of advanced technologies and wide deployment of sustainable energy generation to improve the performance (e.g. efficiency and equipment utilization, power quality and reliability, etc.) of electric utility systems to address the needs of society. Sustainable energy generation deployment is stimulated by political and economical pressure to reduce "greenhouse gases" emissions and the necessity to decrease oil demand dependency. This pressure translates into a rapidly increasing number of sustainable energy financial and legislation tools which are available to energy producers, electric utilities, as well as end-customers from different market sectors.

This paper summarizes current trends in energy and technology investments, regulatory incentives, and other trends that are favorable to the SES/"smart grid" evolution.

## 1. INTRODUCTION

Sustainable energy sources (SES), including distributed generators and energy storage devices, are an essential element of the electric utility “smart grid” concept. In fact, any discussion of the “smart grid” concept that does not consider the impact and contributions of SES technologies is incomplete. SES technologies will play a significant role in achieving almost all of the desired smart grid characteristics, including providing self healing capabilities, providing high power quality to serve the needs of 21<sup>st</sup> century customers, improving the environment, and reducing US dependence on foreign oil. Many regulatory agencies have established guidelines and requirements for achieving an energy portfolio that includes a significant percentage of renewable and clean energy sources. Considerable R&D effort and investments will be needed to achieve these requirements. Fortunately, numerous financial

incentives (tax credits, etc.) and venture capital sources are becoming available to support these efforts. This paper summarizes current trends in energy and technology investments, regulatory incentives, and other trends that are favorable to the SES/"smart grid" evolution.

## 2. EMERGING TRENDS IN ENERGY AND TECHNOLOGY INVESTMENTS

There is a growing interest among government entities, corporations, power utilities and venture financiers on funding new technologies to displace existing technologies that are less efficient and rely heavily on non-renewable energy sources. Various renewable energy technologies have drawn the bulk of political and media attention, as well as the lion's share of capital being invested in the energy technology sector. These technologies include: fuel cells; building integrated photovoltaic systems (BIPV); Cadmium Telluride, Copper Indium Gallium Selenide (CIGS) and Amorphous Silicon (a-Si) thin-film, Concentrated Photovoltaic Systems (CPV), III-V materials for CPV, DSSCs, lithium batteries; flywheel storage systems; “off/on-grid” distributed generation and other new technologies.

In recent years, several significant investment trends have been prominent in the energy sector:

- Major buy-out groups and institutional investors are shifting toward energy generation assets with dependable long-term contractual commitments [1].
- Environmental concerns (e.g. greenhouse gas emissions) and political pressure to reduce dependence on foreign oil has led many states in the US to sponsor new programs that include tax incentives to stimulate the implementation of renewable energy generation (wind, hydro, solar, biomass).
- Governments and private investors have invested significant sums of R&D capital to support energy technologies, such as improved wind turbines, more efficient solar photovoltaic systems, large stationary fuel cells, geothermal and wave/tidal energy solutions. Global venture capital (VC) investment in renewable energy reached \$140 billion in 2007, up 35% from 2006's \$86.5 billion. In the US, VC

investment in renewable energy reached \$3.4 billion in 2007. Investment in solar power led all other renewable energy technologies with over \$1 billion invested. Also, significant amounts were invested in battery technology (\$440 million) and in the energy efficiency/"smart grid" sector (\$420 million) [1, 2]. VC investment in the "green energy/smart grid" sector in 2008 has already exceeded last year's totals (Table 1 and Table 2) and is expected to continue to increase in 2009.

**Table 1 – VC Investment in the "green energy/smart grid" industry in 2008 [3]**

VC Investment in 2008	
Q1	\$0.998 Billion
Q2	\$1.3 Billion
Q3	\$2.8 Billion
Q4	No Data
<b>Total</b>	<b>\$5.1 Billion (2007: \$3.4 Billion)</b>

**Table 2 – Breakdown of VC investment by industry in Q3, 2008 [3]**

Industry Sector	Q3 2008, VC Funding	Number of Investments
Solar	\$1,588 Million	26
Energy Efficiency/Distributed Resources/"Smart Grid"	\$272 Million	14
Geothermal	\$216 Million	4
Automotive/Transportation	\$193 Million	8
Water Technology	\$182 Million	10
Ethanol/Biofuels	\$150 Million	8
Wind Energy	\$140 Million	8
Batteries/Fuel Cells	\$49 Million	4
Carbon/Energy Storage	\$30 Million	3
"Green" Building	\$29 Million	3
"Green" IT/Lighting	\$27 Million	4
Others	\$11 Million	3
<b>Total</b>	<b>\$2,887 Million</b>	<b>95</b>

- Political and economic pressure to use cleaner forms of fuels, such as clean coal and biofuels, is growing in the United States due to the continued economic and geopolitical importance of these fuel supplies—a trend accentuated by the 2005 and 2007 Energy Acts.

### 3. POLITICAL CLIMATE

#### 3.1. Energy Policy

The federal government strongly endorses the use of renewable energy. Going back to President Clinton's 1999 Executive Order 13123 in Section 204, it states, "Each agency shall strive to expand the use of renewable energy within its facilities and in its activities by implementing

renewable energy projects and by purchasing electricity from renewable energy sources." This was further endorsed by President Bush's Executive Order 13423 and EPACT 2005. Executive Order (EO) 13423 requires that agencies: (i) Ensure that at least half of the statutorily required renewable energy consumed by the agency in a fiscal year comes from new renewable sources, and (ii) to the extent feasible, the agency implements renewable energy generation projects on agency property for agency use. The federal government has given support to and is one of the largest purchasers of renewable energy credits (REC's) through utility green power pricing programs. Three of the top 25 purchasers of REC's in the nation are the Air Force, the EPA and the DOE.

Even in the midst of widespread economic and financial crisis, 2007 and 2008 will be remembered for their energy policy landmarks addressing critical renewable energy and smart grid challenges and defining the energy roadmap for years to come. Some of these critical energy policies include:

#### a) The Energy Independence and Security Act of 2007 (H.R. 6)

This bill responds to challenges facing utilities in the twenty-first century. Some of the key aspects are summarized below:

- Title XIII - Smart Grid:
  - Sets aside \$100Million in funding per fiscal year from 2008-2012 in addition to other available reimbursements and incentives.
  - Establishes target goals for the modernization of the electricity grid, which includes maximizing the capacity and efficiency of electricity networks, enhancing electricity grid reliability, reducing line losses, improving security, addressing social benefits and facilitating the transition to real-time electricity pricing. It also allows grid incorporation of more onsite renewable energy generators.
  - Establishes a smart grid advisory committee and task force.
- Declares national energy efficiency improvement goals.
- Requires each electric utility to integrate energy efficiency resources into utility, state and regional plans and adopt policies to establish cost-effective energy efficiency resources.
- Implements roadmaps and demonstration programs for transmission and distribution energy storage systems

## **b) The Emergency Economic Stabilization Act of 2008 (H.R. 1424)**

This bill is in response to the long-awaited extension of Production Tax Credits (PTC) and Investment Tax Credits (ITC). Some of the key aspects of this bill are summarized below:

- Grants an 8-year extension of residential and business ITCs for solar, small-wind and geothermal systems.
- Eliminates the \$2,000 cap on solar residential ITC and allows a 30% residential energy tax credit for small-wind energy and geothermal heat pump property expenditures.
- Eliminates the prohibition on utilities obtaining ITCs.
- Authorizes \$800Million for clean energy bonds and renewable energy generating facilities.
- Gives “clean coal” tax benefits similar to renewable energy generation tax benefits.
- Grants a 1-year extension of PTC for wind projects.
- Grants a 2-year extension of PTC for solar, closed and open-loop biomass, geothermal and hydropower facilities
- Creates a 2-year ITC for marine and hydrokinetic energy technologies (tidal, wave, current, ocean thermal).

## **c) November 4, 2008: Presidential Election**

The 2008 United States Presidential Campaign has been strongly impacted by the current energy crisis resulting in energy policy proposals playing a significant role in the campaigning process for both candidates. A summary of energy policies for the two candidates is provided below.

### **Obama Policies:**

- Create 5 Million new jobs by investing \$150 Billion over the next 10 years to build a clean energy future.
- Within 10 years, save more oil than we currently import from the Middle East and Venezuela combined.
- Put 1 million Plug-In Hybrid cars—cars that can get up to 150 miles per gallon—on the road by 2015.
- Ensure that 10% of our electricity comes from renewable sources by 2012, and 25% by 2025.
- Implement an economy-wide cap-and-trade program to reduce greenhouse gas emissions by 80%, by 2050.

### **McCain Policies:**

- Make the US a leader in the new international green economy.
- Commit \$2 Billion annually in advancing clean coal technologies.
- Construct 45 new nuclear power plants by 2030 with the ultimate goal of constructing 100 new plants.
- Establish a permanent tax credit equal to 10% of wages spent on energy related R&D.
- Encourage the market for alternative, low carbon fuels such as wind, hydro and solar power.

## **3.2. Federal and State Initiatives**

The amount of renewable energy generation that is currently envisioned is staggering. It is possible that a national renewable energy portfolio standard could emerge advocating 20-30% of all energy consumed in the US by the year 2030 be provided by renewable resources. Renewable energy market growth is stimulated by political and economical pressure to reduce greenhouse gas emissions (United Nations Kyoto Protocol, signed by 169 countries, representing 61.6% of emissions, on December 2006) and the necessity to decrease dependency on oil. This pressure translates into a rapidly increasing number of alternative energy financial and legislation tools which are available to energy producers as well as end-customers from different market sectors. Financial tools include [4, 5, 6, 7]:

- Federal and State Tax Incentives,
- Utility Programs.

These financial incentives are available through a variety of grants, loans and rebate programs. Some of the most common programs include [4, 5, 6, 7]:

- Grant, Loan and Rebate Programs
- Personal and Corporate Tax Incentives
- Generation Disclosure Rules
- Property Tax and Sales Tax Exemptions
- Public Benefit Funds
- Net Metering, and Others

State regulations (Mandates, **Renewable Portfolio Standards** and Goal-based programs) require power utilities to generate or purchase a certain percentage of electricity from renewable sources by a specific date. Currently, 30 states have firm policies for renewable energy generation requirements. Other states are considering policies to include alternative energy sources in the regulatory requirements for power generation and energy purchase (Table 3).

**Table 3 - Renewable Energy Portfolio Standards as of 2008 [4, 5, 6, 7]**

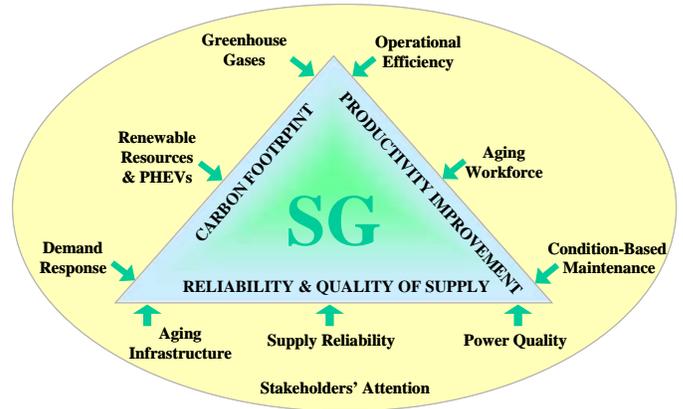
State	Renewable Portfolio Standards Requirements	Date
Arizona	15%	by 2025
California	20%	by 2010
Connecticut	23%	by 2020
Delaware	20%	by 2019
Colorado	20%	by 2020
District of Columbia	11%	by 2022
Hawaii	20%	by 2020
Iowa	105 MW	-
Illinois	25%	by 2025
Maine	10%	by 2017
Maryland	9.5%	by 2022
Massachusetts	4%	by 2009
Minnesota	25%	by 2025
Missouri	11%	by 2020
Montana	15%	by 2015
New Hampshire	16%	by 2025
Nevada	20%	by 2015
New Jersey	22%	by 2021
New Mexico	20%	by 2020
New York	24%	by 2013
North Carolina	12%	by 2021
Oregon	25%	by 2025
Pennsylvania	18%	by 2020
Rhode Island	15%	by 2020
Texas	5,880 MW	by 2015
Utah	20%	by 2025
Vermont	10%	by 2013
Virginia	12%	by 2022
Wisconsin	10%	by 2015
Washington	15%	by 2020

**4. VISION FOR UTILITIES OF THE FUTURE**

**4.1. Development of “Smart Grid”**

In recent years, there has been a rapidly growing interest in what is called “Smart Grid – Digitized Grid – Grid of the Future”. The main drivers behind this market trend and evolving business environment are customer (demand side) empowerment), grid performance (reliability and quality of supply), improved environment (green concept, carbon footprint), productivity improvement and stakeholders’ attention (Federal/State regulators and lawmakers, utility executives, etc.) (Figure 1). The main vision behind this market trend is the use of advanced technologies to improve the performance (efficiency and utilization, power quality and reliability, etc.) of electric utility systems to address the needs of society. The “Smart Grid” concept is enabled by bringing together various technologies/solutions from several industries such as telecommunications, the internet and information/data computing. The “smart grid” concept should be viewed in light of it bringing evolutionary rather than revolutionary changes to the industry.

**Figure 1 – “Smart Grid” market and business drivers**



Overall, this market trend requires a new approach to business and workforce management, system design, re-design and predictive equipment maintenance, system integration and new technology implementation. In addition, it will be necessary for utilities to develop well defined engineering and construction standards and operation practices that address future high penetration levels of renewable energy generation.

**4.2. Energy Efficiency and Equipment Utilization**

Implementation of the “smart grid” concept, supported by an increased level of renewable energy generation, requires more effective management of generation, transmission and distribution systems. Many utilities and states have established financial incentives to encourage energy efficiency and conservation at the institutional and customer/end-user level.

Experience shows that energy efficiency programs can help to defer the addition of a new energy infrastructure, provide energy savings to consumers, improve the environment, and spur local economic development. Various studies have found that the adoption of economically attractive, but as yet untapped, energy efficiency resources could yield more than 20% savings in the total electricity demand nationwide by 2025. Implementing energy-efficient DER would help manage load growth and would offer substantial economic and environmental benefits across the country. Extrapolating the results from existing programs to the entire country yields an annual energy bill savings of nearly \$20 billion, with net societal benefits (e.g. customer investment, portfolio choice, etc.) of more than \$250 billion over the next 15 years. This scenario could defer the need for 25,000 megawatts (MW) of new generation capacity and also reduce US emissions from energy production by more than 190 million tons of CO<sub>2</sub>, 45,000 tons of SO<sub>2</sub>, and 35,000 tons of NO<sub>x</sub>, annually.

Even though energy efficiency and power grid management play a significant role in the energy market landscape, there are a number of well-recognized barriers that may impact the implementation of new energy efficient technology (Table 2).

**Table 2 – Market barriers to energy efficiency**

Barriers	
Product/Technology	Time unproven technology
"Split" Incentive	Economic benefits of energy conservation do not accrue to the person saving energy
Financing	Liquidity constraints, refers to restrictions on capital availability for potential borrowers
Market	Refers to product supply decisions made by equipment manufacturers. This barrier suggests that certain leading companies may be able to inhibit the introduction of energy-efficient, cost-effective products by competitors
Utility/regional planning	Does not allow energy efficiency to compete with supply-side resources in energy planning
Customers	Limited information and awareness on energy efficiency and energy saving opportunities

## 5. SUSTAINABLE ENERGY TECHNOLOGIES IN SUPPORT OF “SMART GRID” CONCEPT

The bulk of electric power used worldwide is produced at large central station power plants, most of which utilize fossil fuel combustion or nuclear reactors. The majority of these central station generators have a maximum output of between 150 and 800MW. This makes them relatively large in terms of both physical size and facility requirements as compared to many generation facilities utilizing renewable energy technologies. The main reasons why central station power plants still dominate current electricity production include economies of scale, fuel cost and availability, and lifetime. Increasing the size of a production unit decreases the cost per MW. However, the advantage of economy of scale is decreasing—technological advances in energy conversion and the availability of new technologies have improved the economy of smaller renewable energy generation (REG) units. Some of the key benefits of REG include: higher efficiency; improved security of supply; improved demand-response capabilities; avoidance of overcapacity; better peak load management; reduction of grid losses; distribution and transmission network infrastructure cost deferral; power quality support; reliability improvement; and environmental and aesthetic concerns. REG offers extraordinary value because it provides flexibility in choosing between cost and reliability. In addition, REG may eventually become a more desirable generation asset because it is “closer” to the customer and is more economical than central station generation and its associated transmission system. The disadvantages of REG

include ownership and operation, time unproven technology, cost of connection, metering and balancing, and potential safety issues.

Current and continuously improving renewable energy technologies in support of the “smart grid” concept include:

- Cadmium Telluride, Copper Indium Gallium Selenide (CIGS) and Amorphous Silicon (a-Si) Thin-film
- Multi-junction Photovoltaic (PV) (higher efficiency than traditional panel PV)
- Concentrating Solar PV (CSPV)
- Building integrated PV (BIPV)
- Distributed small-wind turbines
- Small 1-5 MW industrial biogas turbines (~ 40% efficiency)
- Recuperated small biogas turbines (34-43% efficiency)
- Microbial fuel cells
- Power Chips (up to 70% efficiency)
- Various wave, tidal and run-of-river technologies

Some renewable sources are intermittent, meaning that the load or capacity factor is much less than one, typically 0.25 – 0.40 for wind farms and 0.10 – 0.20 for photovoltaic systems. This implies that renewable energy sources might deliver power only at certain times of the day that do not necessarily match the energy consumption patterns of customers. To address this mismatch between time of production and time of consumption, energy storage needs to be implemented. Most studies confirm that renewable energy penetration levels of 15-20% can easily be absorbed in the electric network without major operational changes and upgrades. However, large-scale implementation of sustainable energy technologies can lead to situations in which the grid evolves from a “passive” (local /limited automation, monitoring and control) system to one that actively (global/integrated, self-monitoring, semi-automated) responds to the various dynamics of the electric grid. This poses a challenge for operation and management of the grid as the network no longer behaves as it once did. Consequently, the planning and operation of new systems must be approached somewhat differently with a greater amount of attention paid to global system challenges.

Some of the key technical and non-technical challenges include, but are not limited to the following:

- Financial constraints:

- Many “green/smart grid ” technologies are still relatively expensive
- Difficulties in financing, bonding and insuring large projects
- Slow-moving customers and utility industry:
  - Risk-averse mentality
  - Evolving technologies
- Uncertain life-span of new technologies (relatively short performance record).
- Power and data interfaces and interconnections for “Smart Grid” need improvement.
- Flexible and cost-effective energy storage systems should be developed and integrated into the “smart grid”.
- Data management needs to be focused on integrating different technologies in a plug-and-play fashion.
- Standards and regulations should be tightened since they are the key driving force in limiting interconnection problems.
- Utility acceptance and revenue generation from “smart grid” options are paramount.

## 6. CONCLUSIONS

Today’s utilities, developers and commercial entities plan for increased sustainable energy generation portfolios in order to provide for a more oil independent energy future. This trend is also rewarded by federal and state governments through various tax and production incentives and other initiatives driven by many power utilities. The increased penetration levels of sustainable energy sources as part of the generation mix brings new technical and portfolio management challenges and opportunities. The Smart Grid concept is an industry-wide enabler to providing a Plug-and-Play environment for many sustainable and renewable technologies. In addition, effective sustainable portfolio management will help to decrease implementation and operation costs related to a wide variety of smart grid/renewable energy technologies. The quest continues to develop more environmentally friendly, but cost-effective technologies utilizing all the available incentives into an existing and aging T&D power system infrastructure, using a limited resource pool.

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# Interoperability Concerns in Advanced Metering Infrastructure

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## Abstract

While Advanced Metering Infrastructure (AMI) has great potential benefits for utilities, a number of the interfaces in these metering architectures also carry with them substantial risk. Most utilities deploying AMI are not only purchasing AMI systems, they are performing research and development on AMI interfaces and products in partnership with their suppliers. While the industry is scrambling to develop standards, utilities have other deadlines and must decide to purchase something in the meantime. This can lead to a variety of interoperability problems.

At the highest level, interoperability is dependent on all stakeholders agreeing on exactly what they are talking about. For the purposes of facilitating discussion in the industry, this paper proposes a common naming convention for the most significant components and interfaces of an AMI system, and then uses this convention to describe some of the most common interoperability concerns in the AMI systems being currently deployed.

## 1. AN AMI NAMING CONVENTION

The following common names are proposed for the communications networks and components of an Advanced Metering System. Some of these names are taken from the IEC 61968 Part 9 standard [1], currently in development. Names other than those proposed are identified in *italics*.

### 1.1. Communications Networks

In general, an AMI may be divided into five different communications networks or domains, as illustrated and described in Table 1. Figure 3 illustrates typical components and technologies used in each domain.

Of the names shown here, two of the five are controversial. The terms “WAN” and “HAN” have been widely accepted (although “backhaul” is still common) and the term “External Network” is very generic and not likely to meet with opposition. However, there is still no consensus on what to call the “last mile” network to the meters. “NAN” is a good candidate, but is not common usage outside the industry the way that “WAN”, “LAN” and “HAN” are.

“Field LAN” has the advantage of being clearly distinguishable from a WAN or from a LAN used within a building, and can be applied to distribution automation as well as to metering. The term “Utility Information Bus (UIB)” is still common in the enterprise domain, but “ESB” seems to be more popular, perhaps again because it is more generic and less utility-specific.

**Table 1 - Proposed AMI Network/Domain Names**

Name	Role / Description	Other names
Home Area Network (HAN)	Connects devices on the customer premises to the Premise Gateway or Meter. Not always in a home, but in the term common use and easy to distinguish from other networks.	<i>Local Area Network, Personal Area Network, Home Automation Network</i>
Field Local Area Network (Field LAN)	Connects the Meters to Collectors. May also be used by distribution automation devices to communicate from pole-tops and pad mounts.	<i>Local Area Network (LAN), Neighborhood Area Network (NAN), Meter LAN, Field Network, RF LAN, Wireless Mesh, Last Mile</i>
Wide Area Network (WAN)	Connects the Collectors to the Metering System. Generally very high-bandwidth, very reliable technology. Often provided by a third party and shared with transmission and distribution automation.	<i>Backhaul Network, T&amp;D Network, SCADA Backbone, Substation WAN</i>
Enterprise Service Bus (ESB)	Connects the Metering System to the Meter Data Management System and the various other enterprise applications, particularly Outage Management, Energy Management, and Customer Information Systems.	<i>Corporate Network, Back-office Network, Application Bus, Utility Service Bus, Utility Information Bus, Message Bus, Enterprise Network</i>
External Network	Connects the utility to various third parties such as regulators, aggregators, energy service providers, and (again) the customer, usually via the Utility Web Site.	<i>Internet, Public Networks, B2B</i>

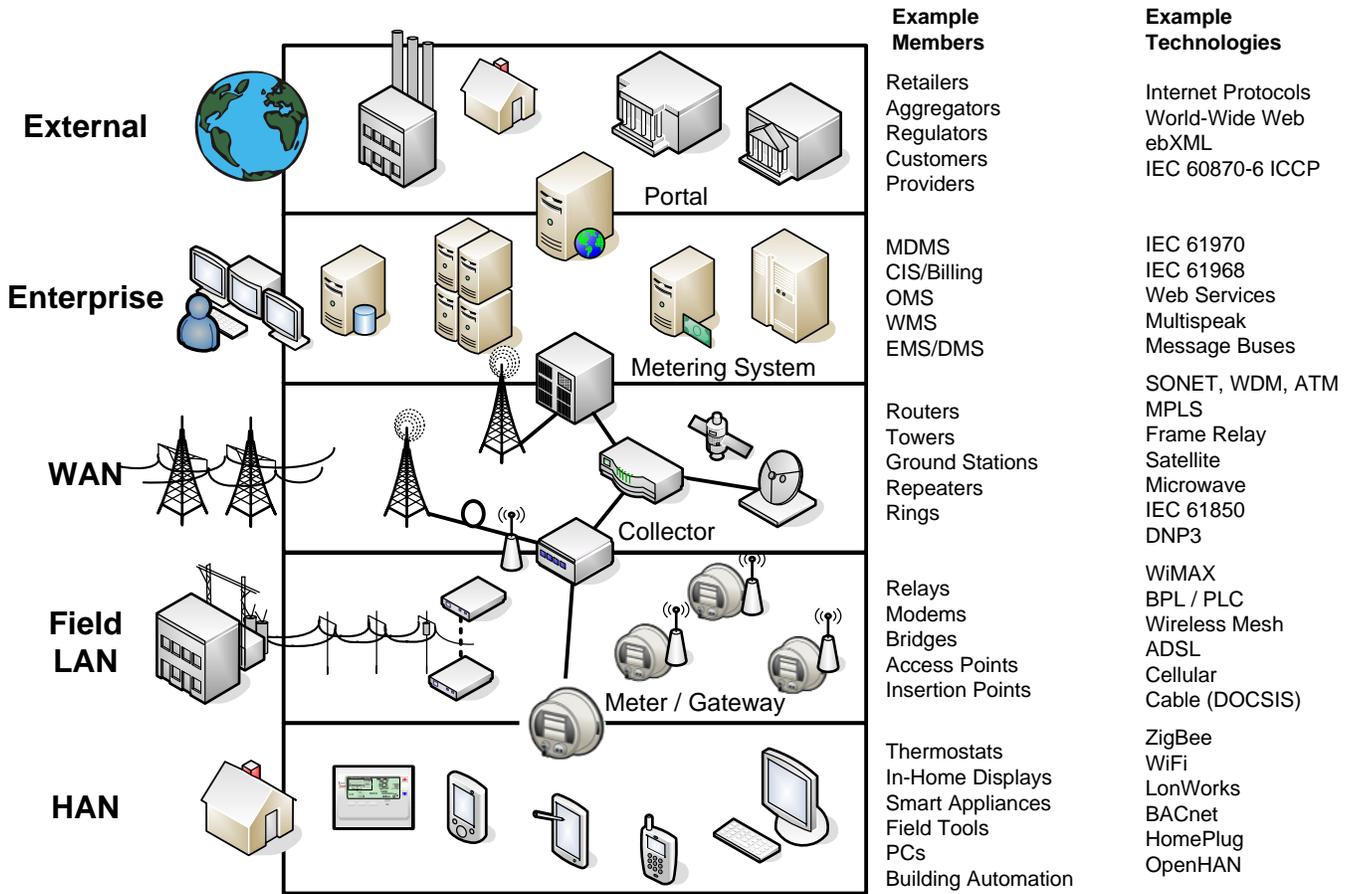


Figure 1 – Simplified Overview of an Advanced Metering Infrastructure

1.2. HAN Components

Table 2 lists components commonly found in the HAN domain.

The term “Meter” is fortunately non-controversial, although some people seem intent on distinguishing between an AMI meter and other types of meters. Of course, the term “Smart Meter” is very popular in the media and with customers. The adjectives “AMI” or “Smart” can be easily dropped from “Meter” if one assumes the conversation is about AMI. The term “Smart Appliance”, however, seems to have stuck in the minds of vendors, utilities and customers alike.

The terms “PCT” and “IHD” are now very common due to widespread discussion in the California AMI initiatives. It is true that displays are not always used in a home, but the term is shorter than “premise” and is very clear. The term “PCT” has in fact become somewhat infamous thanks to public concerns about mandated deployment of these devices in California legislation.

The distinction between a home or building energy management system and the large utility EMSs often causes con-

fusion and needs to be clarified. BMS is not the most popular term in use, but it sounds much like EMS and can usually be accepted by both home automation and utility operations proponents.

The greatest naming controversy in the HAN area is the concept of the Premise Gateway. Some people don’t understand why it should have a separate name – they assume that the utility gateway to the home will always be the meter. Others, primarily in the home or building automation fields, reject the idea of the meter as the gateway and assume access to the home will be through the Internet or some other mechanism. An older term, “consumer portal”, has never caught on. Because of the underlying philosophical differences in the industry, it is important to note that the Meter and the Premise Gateway are sometimes, but not always, the same component. “Premise” is used rather than “home” in this case to be more generic.

“Field Tool” and “Load Control Device” are common generic terms for these components and often needed to avoid using vendor-specific terms. “Field Tool” is a more generic form for a potentially large set of multiple tools used for

installation, maintenance, repair and work order management.

**Table 2 – Proposed HAN Component Names**

Name	Role / Description	Other names
Meter	Primary measurement device and often the gateway to the HAN.	<i>Smart Meter, AMI Meter</i> , vendor-specific names
Smart Appliance	A home appliance such as a refrigerator or oven that can adjust its load in response to messages from the AMI.	Vendor-specific names
PCT	Programmable Communicating Thermostat. Can react to demand response messages from the AMI.	<i>Smart Thermostat, Home Automation System</i>
IHD	In-Home Display. Any device that displays information from the meter or utility to the customer.	<i>Premise Display, Customer Display, Home Automation System</i>
BMS	Building Management System. Monitors, controls and optimizes load on the customer premises through a number of other devices autonomously and in coordination with the AMI.	<i>Energy Management System, Home Automation System</i>
DER	Distributed Energy Resource. Generation or storage equipment on the premises.	<i>Distributed Generation</i>
Load Control Device	Generic name for PCT or BMS, or a Smart Appliance. Distinct from a display.	<i>Customer Equipment</i>
Customer Equipment	Generic term including any of the other devices listed here not owned by the utility.	
Field Tool	Hand-held tool that connects to the meter, often over the HAN, to perform maintenance, installation, and processing of work orders.	<i>Workforce Tool, Deployment Tool, Maintenance Tool, Installation Tool</i> , Vendor-specific names
Premise Gateway	Performs the function of converting messages between the Field LAN and the HAN. Often, but not always, this function is performed in the Meter.	<i>Meter, Set-Top Box, Gateway, Home Interface, Consumer Portal</i>

**1.3. WAN and Field LAN Components**

The name of the component listed in Table 3 as the Metering System is perhaps the most disputed of any listed in this paper. Most AMI experts are familiar with it under the name “head-end”, but the informal quality of that name prevents it being used in any official capacity. Network Management System is an accurate description of its duties, but one that is easily confused with systems common in the

general computing world that use Simple Network Management Protocol (SNMP) and other such protocols to monitor traditional IT networks. The name Automated Data Collection System oversimplifies its duties and ignores the tasks of control and configuration. “Metering System” is the term used in the draft IEC 61968-9 and as such represents as much of an “official” consensus as can be said to exist.

**Table 3 – Proposed WAN and Field LAN Names**

Name	Role / Description	Other Names
Collector	Gathers and forwards data from Meters onto the WAN and vice versa.	<i>Data Concentrator, Neighborhood Collection Point, Cell Relay, Aggregator, Meter</i>
Metering System	Responsible for establishing and maintaining communications with meters, forwarding data and events to the MDMS and other clients, balancing the communications load on the Field LAN, and providing clients with interfaces to control, configure and perform diagnostics on meters.	<i>Automated Data Collection System, Metering Head-End, Data Collector, Meter Monitoring System, Network Management System.</i>

**1.4. Enterprise Components**

In the enterprise domain, there are fewer disputes about names but more disputes about what functions those names imply, since the systems available from vendors may combine or separate many of the functions listed in Table 4.

There is much disagreement regarding where meter management, diagnostics and maintenance functions reside: within the Metering System, the Meter Data Management System, the Customer Information System, or as a separate component. It is clear that the tasks of performing meter diagnostics and configuration changes must be performed *through* the Metering System, but many architectures locate the information storage and decision-making process for these tasks in a variety of other locations.

IEC 61968-9 notes that Meter Asset Management and Meter Maintenance are often subtasks of a more general utility Asset Management system. Under the principle that less duplication and more integration of utility systems is generally considered better, that grouping and naming is what is proposed here.

**Table 4 – Proposed Enterprise Component Names**

Name	Role / Description	Other Names
Meter Data Management System (MDMS)	Performs Validation, Estimating and Editing (VEE) on metering data. Prepares data for billing and stores it temporarily.	<i>Metering Database</i>
Meter Data Warehouse	Provides long-term storage of meter data, advanced querying capability, and a common point of access for multiple clients. Sometimes considered part of the MDMS.	<i>Historian, Planning Database, Load Monitoring Database, Usage Data Warehouse</i>
Load Management System (LMS)	Permits energy marketers, system operators, or other clients to manage load, for system reliability or economic purposes. May consist of two separate systems: <i>Load analysis</i> , which determines and presents what resources are available for dispatch, and <i>load control</i> , which makes the actual requests to the Metering System or other resources.	<i>Demand Response Analysis and Control System, Load Control System</i>
Asset Management System (AMS)	Stores information on the current configuration, status and health of corporate assets including meters. Schedules maintenance and issues work orders as well as performing online configuration and diagnostics through the Metering System.	<i>Meter Management System, Meter Asset Management, Meter Maintenance</i>
Outage Management System (OMS)	Detects, tracks, and locates outages and their root causes based on input from a variety of sources including the metering system.	
Work Management System (WMS)	Helps operators to dispatch field crews via a variety of possible means including AMI Field Tools.	<i>Workforce Management System</i>
Customer Information System (CIS)	Calculates and sends customer bills, permits representatives to perform diagnostics through the Metering System, and stores information associated with customer contact including: <ul style="list-style-type: none"> <li>• Customer characteristics</li> <li>• Program and rate choices</li> <li>• Contact information</li> <li>• Program participation history</li> <li>• Contact log</li> <li>• Customer equipment</li> <li>• Distributed energy resources</li> <li>• Meter identifiers</li> <li>• Prepayment information</li> </ul>	<i>Customer Care System, Customer Relationship Management System, Customer Communications System, Billing System</i>

Name	Role / Description	Other Names
Revenue Protection System (RPS)	Suite of applications that analyzes metering data to determine whether diversion or theft is occurring. May be part of the MDMS or AMS.	<i>Diversion Analysis Application</i>
Geographic Information System (GIS)	Contains information on the location of corporate assets including meters, and may display that information graphically or in other forms.	<i>Outage Management System, Energy Management System</i>
Energy Management System (EMS)	Manages load, and switching for the entire electrical network, but particularly the transmission and generation portions.	<i>Grid Control Center, SCADA Master</i>
Distribution Management System (DMS)	Overall term for a system composed of several of the other enterprise functions listed here, applied particularly to the distribution portion of the network.	<i>Distribution Control System, SCADA Master</i>
Portal	Provides secure access to metering data and other services associated with the AMI to a variety of external clients including customers, regulators, aggregators, service providers and other utilities. Often implemented using web technology.	<i>Utility Web Site, Gateway, Web Portal, DMZ</i>

Similarly, another set of functions that are often located in a variety of different components is listed in Table 4 as the Customer Information System. Most utilities recognize that these functions are better grouped together, but often separate them because they already have legacy systems that only provide some of the features. This can cause integration problems because the legacy systems may not provide some the interfaces necessary to manage customers in coordination with an AMI.

A GIS is another idealized system whose functions may be spread among other systems. In particular, the features of OMS, GIS and AMS may be intertwined in providing equipment monitoring and planning functions.

**2. AMI INTEROPERABILITY RISKS**

Although a common set of names for AMI components such as that proposed here would greatly improve the dialogue around AMI, there are many more important concerns. Some of these are listed in the sections that follow. These concerns are drawn from the experience of the author's organization in performing requirements gathering and architecture analysis for several recent AMI projects.

**2.1. Topology**

Many of the use cases currently proposed for AMI require the use of electrical network topology information to be effective. Specifically, they require software applications to know which meters (and therefore customers) are connected to a particular circuit, circuit segment, distribution transformer, and/or phase. Table 5 provides some examples of such uses cases [2 and others] and how providing detailed topology information to the AMI system can improve the associated business case.

**Table 5 – Examples Using Topology Information in AMI**

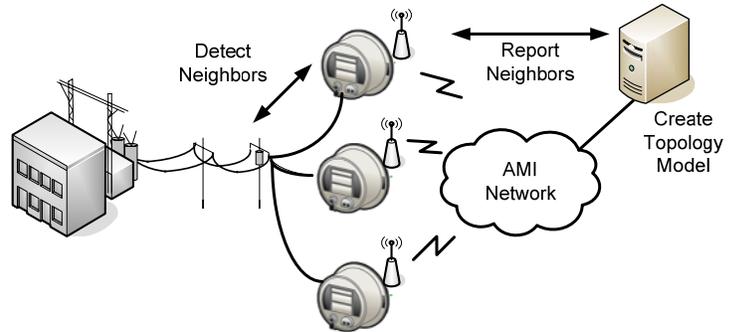
Typical Scenario	Use of Topology Information
Operator locates outage and restores service	Find outage based on power failure reports from meters and knowledge of their electrical and geographic location. Verify restoration by querying meters along the circuits believed to be restored.
Revenue manager detects theft using transformer meters	Compare load measured at transformer with total load of all customers located on that transformer and investigate any areas showing significant differences
Revenue manager detects theft from unusual usage pattern	Compare load profile of customers with a randomly selected set of nearby customers having similar characteristics. Flag significant differences for investigation.
Capacitor bank controller optimizes voltage on feeder	Analyze voltage profile measured by all meters on a feeder or neighboring feeders before deciding to change capacitor bank settings
Operator reconfigures feeders to prevent overloading	Examine the historical load profile of neighboring feeders or segments, as calculated from the aggregated load of customer meters on those feeders. Shift load from overloaded feeders to those with lower predicted peaks.
Planner improves distribution transformer utilization	Calculate the historical load profile for each transformer from the aggregate load of the customers connected to it. Reconfigure the distribution network to shift load away from overloaded transformers.

As seen from the table, the benefits of using detailed topology information in conjunction with an AMI can be significant and they typically improve with the quality of the topology information available. However, there are significant interoperability concerns associated with these use cases, including the following:

- **Where does the topology information come from?** Many utilities already store topology information down to the circuit level in their GIS. However, acquiring data that maps all meters in the utility’s service are to circuits, segments and transformers can be extremely labor-intensive and costly. Some utilities find that deploying an AMI is an opportunity to gather this data,

while others are concerned with deploying as quickly as possible and cannot spare the expense.

- **How to keep the topology model up-to-date?** Some utilities are discussing the possibility of an automated method using, for instance, power-line carrier technology. Devices located at the meter and either the transformer or substation would exchange messages over the electrical circuit to determine which were physically connected, then pass the information to a central application that would build and store a model, as illustrated in Figure 2.



**Figure 2 – Generation of a Topology Model**

Ideally, such devices would be integrated into the meters; but if the primary communications for the meter was not already power-line carrier, that could significantly add to the cost of the AMI. A somewhat less sophisticated method that has been suggested is to inject controlled sags into the circuit and make use of some meters’ ability to detect them. In any case, such technology is only at the planning stage, therefore not standardized, and hence interoperability challenge.

- **What level of detail and accuracy to keep?** As noted in Table 5, there are several different uses of topology information, each possibly requiring different levels of detail and accuracy of information. If there are several different software applications that must make use of this information, they must be prepared to deal with varying quality of information and likely will need to be able to process the lowest common denominator. This flexibility is required for interoperability.
- **Where is the topology information stored?** The typical answer is “in a single location”. However, it is not always easy to agree on what that location should be. The GIS is an obvious choice, but the OMS and MDMS are also possible candidates. There may already be some topology information stored in one location, but this location may not always be appropriate for the future depending on the use cases being implemented. A more complex answer is “it

doesn't matter where, as long as the format for exchanging it is standardized". This then becomes an interoperability issue.

- **Who uses the topology information?** It is not always clear where the functions described in Table 5 should be performed. Some of them were impossible, less accurate, or inefficient prior to the advent of AMI. Utilities must either assign these tasks to existing applications such as those listed in Table 4 or invent new applications to do them. Unless and until such applications are standardized, an interoperability concern exists.

**2.2. Filtering Events**

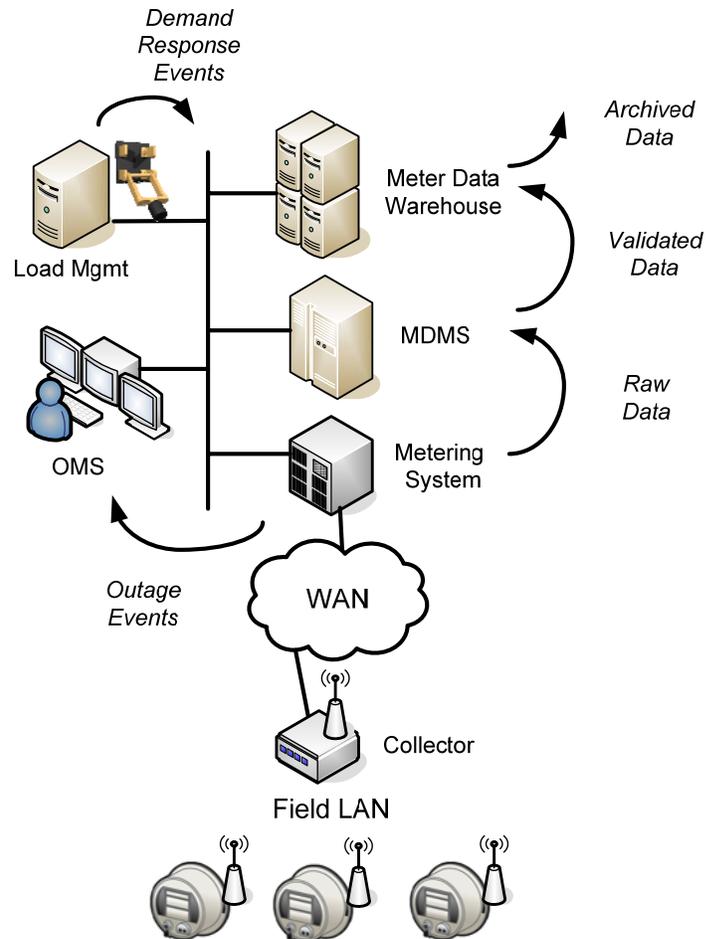
The sheer volume of messages potentially produced by an AMI with millions of customers would be a problem if each meter was permitted to transmit whenever it had new information. Even when using communication technologies that provide large amounts of bandwidth, there are processing concerns at collectors and back office systems.

Therefore a meter normally buffers its interval measurements, demand response events, power outage notifications, or theft occurrence events until the end of the day, and then transmits them all together. This reduces the number of messages transmitted and permits the Metering System and MDMS to process them in batches.

However, certain use cases and classes of events, particularly those associated with outage management, require that events be transmitted as they occur. A power outage indication, for instance, is not useful if it is reported at the end of the day. This leads to the following issues:

- **Where to filter events?** Events could be filtered by the Collector, by the Metering system, by the MDMS, or by the Outage Management System itself, as illustrated in Figure 3. Some architectures even use the functions of the historian or Meter Data Warehouse to do so. If sufficient bandwidth is available in the communications system, it is preferable to throttle or filter events at the highest level possible. This provides the decision-making software with the most possible information, and permits the most sophisticated algorithms for deciding what to filter. Systems with limited bandwidth may need to filter at lower levels, such as the collector.
- **What criteria to use for filtering?** An example of a simple filtering algorithm would be a system that ignores power-outage events that are followed by a power-restored event within a configured length of time. However, much more sophisticated algorithms could be used depending on the location where they are applied.

The interoperability issue arises if different vendors' equipment are used for different functions in the AMI, and they make different assumptions about where and how data is filtered.



**Figure 3 – Possible Candidates for Event Filtering**

**2.3. Other Outage Management Issues**

Besides the concern about the number of event messages transmitted across the AMI, the use case of outage management raises some other interoperability issues:

- **Which system makes the decisions?** There are at least three different situations that need to be distinguished by an outage management design. These situations are meter failure, communications system failure, and power system failure.

The metering system is clearly the expert on whether a meter failure has occurred. However, it may not "own" the entire communications network. The WAN may come from a third-party provider and therefore have a separate network management system.

Similarly, the outage management system is the expert on whether a power outage has occurred. However, without input from the metering system, the OMS may not have the most accurate information.

Most utilities prefer to have the OMS be the final decision maker, but even if one makes that assumption, there are many different messaging paths and sequences that could take place between the metering system, OMS and any third-party telecom network management system. For true interoperability, this “meta-model” of how outage management decisions are made should be standardized.

- **How to coordinate outage management, demand response and theft detection?** Theft detection algorithms are typically looking for a particular sequence of meter events, or a particular usage history profile, that indicates diversion of energy. For these algorithms to be useful, however, they must have access to information about the timing of outages or demand response events. This will permit the algorithms to compensate for the fact that the customer’s behavior and the meter events recorded during outages or demand response were not typical, and therefore reduce false positive indications of theft.

Similarly, there may be a number of other applications such as distribution planning and load research that also need access to this information. In particular, applications that evaluate the effectiveness and performance of demand response programs need a way to correlate each event with the usage and demand measurement data recorded during that event.

There are a number of different methods that could be used to integrate outage and demand response information with usage data. For instance, it could be added after the event to the measurement data when it is stored in the MDMS or Meter Data Warehouse, as illustrated in Figure 4. However, there is the problem of ensuring that the data from all the affected meters and all the affected intervals are correctly tagged. There would be a time period in which the data is not tagged and could confuse some applications.

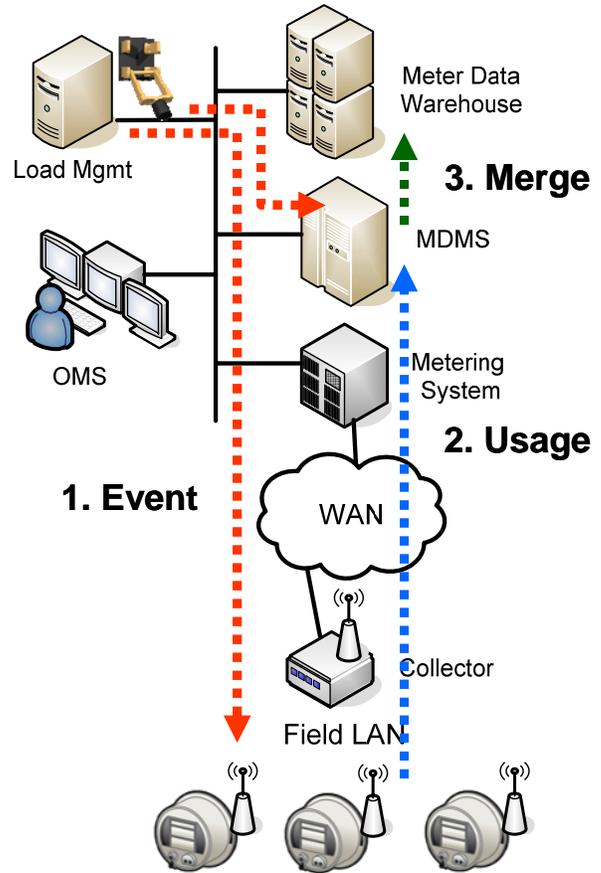


Figure 4 – Merging Event and Usage Information

Alternately, the event information could be added “on the fly” to the usage data by the Metering System since all messages to and from the meters must pass through that system. However, this would require a system that is normally designed with a high-performance “pass-through” architecture to record and update state information.

The most accurate and efficient method would be to have the meter do it, as illustrated in Figure 5. If the meter reports all data with a quality flag (some use the term “status code”) indicating when there is an outage or a demand response event underway, that information will follow the measurement data throughout its lifetime. There would be no need for coordination of timestamps later on. Most Metering Systems permit quality tagging of data, but not all systems do it the same way.

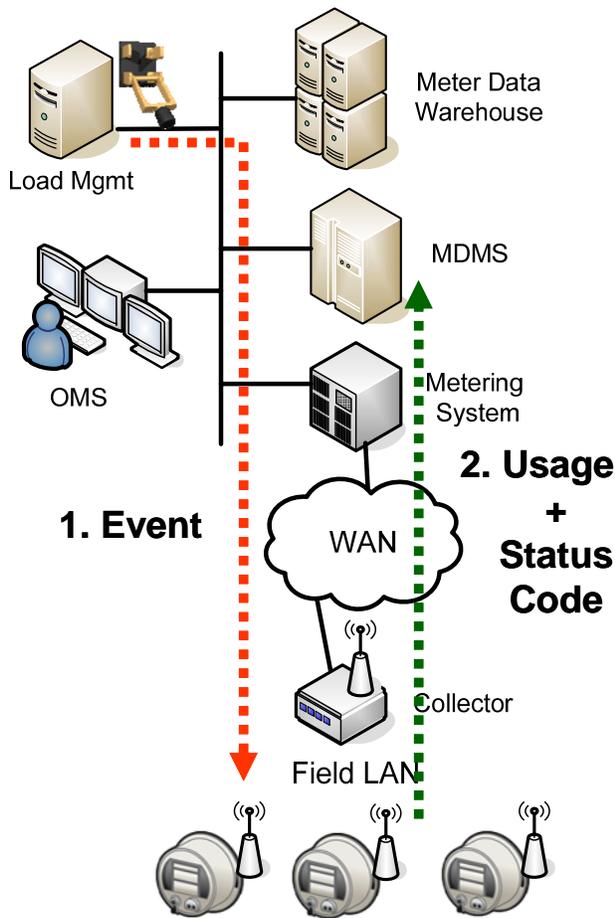


Figure 5 – Tagging Usage Data with Status at the Meter

**2.4. Real-Time Access vs. Long-Term Storage**

The chief benefit of deploying an AMI is the large amount of extremely accurate customer data it produces that can be used for a variety of purposes within the utility. However, there may be so many requests for this information that it raises a major architectural and interoperability issue: the trade-off between real-time access and long-term storage of data. This trade-off can be expressed through the following questions:

- **How to ensure the billing process is not delayed?** While it is desirable to have all metering data stored in one location for easy access, such a system is necessarily also on the critical path for generating customer bills. To avoid burdening this system (typically the MDMS) with the data requests of a potentially large number of enterprise client and requests, it is usually considered necessary to have a separate component serve as the access point. This component variously called a historian, data warehouse, or meter archive. This paper proposes the name Meter Data Warehouse.

- **How to ensure a common data interface?** Most Meter Data Management Systems not only VEE the data, but also store it for some length of time before updating the Meter Data Warehouse. For ease of interoperability, it is important that applications can access the information they need through the *same* interface regardless of whether it is in “permanent” or “temporary” storage. Some MDMS vendors claim that a separate Meter Data Warehouse is unnecessary with proper design of the database, and an ongoing exchange of technical papers on the topic attests to the fact that the problem has not been definitively solved yet.
- **How often should data be updated?** Figure 3 illustrates the typical path of usage data. Some data may need to be updated along this path quicker than others, depending on the use case scenario, as indicated in Table 6. Applications may need to access the data from via different systems depending on their needs. The speed of transfer of data from temporary storage in the MDMS to long-term widespread access in the Meter Data Warehouse will likely need to vary depending on the type of data. Time requirements for such updates range from minutes to years.

Table 6 – Examples of Data Types Scenarios and Interfaces

Data Type	Possible Scenarios	Possible Interface
Hi priority raw data, e.g. events	<ul style="list-style-type: none"> <li>• Operator locates outage and restores service</li> <li>• Power system automatically reconfigures for reliability purposes</li> </ul>	Metering System
Short term validated data	<ul style="list-style-type: none"> <li>• Customer views previous day's usage history and cost</li> <li>• Customer reduces demand in response to pricing event</li> </ul>	MDMS
Long-term validated data	<ul style="list-style-type: none"> <li>• Load researcher performs study of customer behavior</li> <li>• Planners optimize asset utilization</li> </ul>	Meter Data Warehouse
Calculated data	<ul style="list-style-type: none"> <li>• Revenue manager detects theft using transformer meters</li> </ul>	Other databases

- **How many databases are needed?** The Meter Data Warehouse may not be a single database, nor may it be homogeneous. Some utilities may prefer to keep calculated data, such as geographically aggregated customer load, in a separate location. Others may prefer to have a single point of access for all data associated with a customer or meter.

**2.5. Proprietary Field LANs**

One of the primary interoperability risks for a utility wishing to deploy AMI is that there are few Field LANs that

are completely based on open standards, and even fewer that are economical.

Field LANs in current AMI offerings are typically wireless mesh radio, either licensed or unlicensed, or power-line carrier, either narrowband or wideband. These technologies are almost invariably proprietary. Open standard technologies for reaching the customer premises, such as cellular, WiMAX, ADSL, cable or fiber-to-the-home, have reliability concerns or more often, are not economical for millions of devices. They are often used to reach the Collector level, but are typically not used to reach individual meters except in extreme rural cases that cannot be reached in any other way. In some cases, such as Broadband Over Power Line (BPL), an open standard is in development but not available yet.

The typical interoperability solution for a situation such as this is to use an open standard upper layer technology to bridge or route messages over top of the proprietary lower layers, as shown in Figure 6. Ideally, this would be a network layer technology, to permit easy routing between networks from different vendors. The open network layer of choice today is the Internet Protocol (IP), either the typical version 4 or version 6, which provides better inherent security and higher numbers of devices.

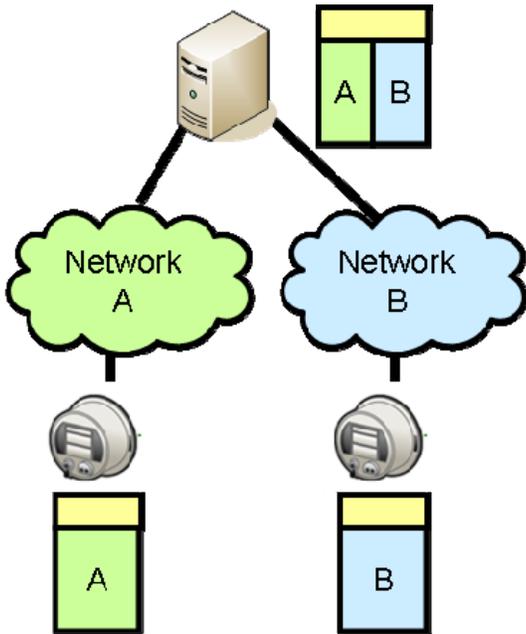


Figure 6 – A Common Upper Layer for Field LANs

Unfortunately, there are three factors typically preventing vendors from deploying IP on their Field LANs.

- **Bandwidth.** Many vendors' Field LAN technologies do not have the bandwidth to support IP messaging at all.
- **Allocation.** Even those Field LANs that could support some IP messaging are typically not prepared to permit any of several million devices to transmit at any time, as implied by the IP networking model.
- **Routing.** Many of these technologies have their own network layer or proprietary routing mechanism that would have to be integrated with IP in some way.

With this in mind, some vendors are offering Field LANs with an open standard application layer, namely ANSI C12.22 (including ANSI C12.19 data models). In theory, this would permit a Metering System using ANSI C12.22 to communicate over IP or variety of Field LANs with any meter that also supports ANSI C12.22.

Unfortunately, in practice, no such multi-vendor Metering System exists. The ANSI C12.22 standard permits so much flexibility in implementation that even Metering Systems that support ANSI C12.22 typically only support meters from the same vendor.

The newest release of the standard may provide some help with this issue, but the best hope for interoperability in this area is for a an industry consortium to restrict the options permitted in implementing the standard, and for technology to advance to the point where higher-bandwidth Field LANs become common.

## 2.6. Distribution Automation

Related to the proprietary Field LAN problem is the issue of permitting distribution automation devices to access the Field LAN.

For many utilities, building an AMI network that can reach every customer could finally make the business case viable for widely deploying distribution automation. Applications such as automatic fault location, isolation, sectionalization and restoration (FLISR) and automated Volt/VAR optimization could become widespread.

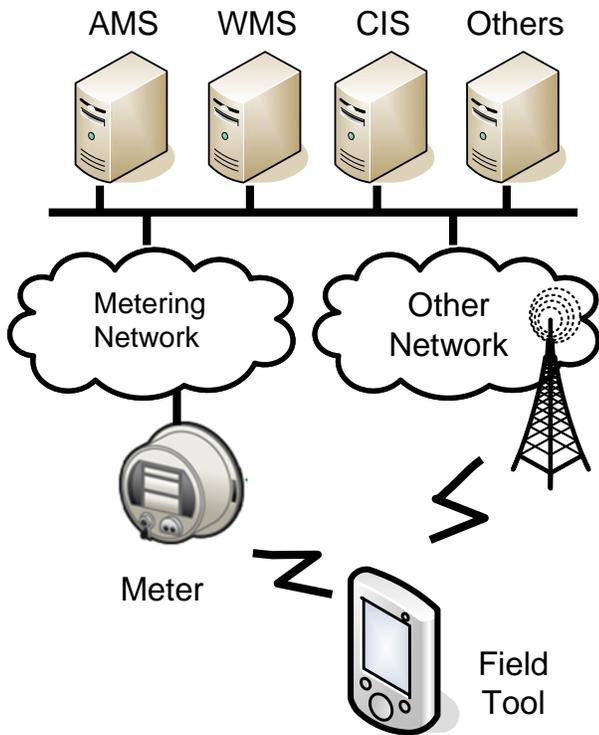
Unfortunately, for the same reasons as listed in the previous discussion concerning the Internet Protocol, suppliers are reluctant to permit distribution automation devices to use their Field LANs. Some are prepared to work with DA device vendors to implement custom interfaces to their Field LAN for pole-top reclosers, switches, etc. However, few are prepared to accept wholesale tunneling of distribution automation messages across their Field LANs. None have made provisions for DA devices or any component other than the Metering System to read measurements from meters. Despite the new applications such distributed

access would enable, suppliers are unanimous in designating the Metering System as the only access point to meter data.

Again, the only solution to this problem may be to wait for a gradual increase in the amount of bandwidth available on Field LANs until the allocation issue is no longer a concern, and IP-based messaging between distribution automation devices can take place.

**2.7. Field Tools**

Hand-held field tools for the installation and maintenance of meters have great potential for speeding up the process of AMI deployment. A tool that could communicate with AMI applications over cellular networks on one hand and directly to the meter via the HAN on the other, as shown in Figure 7, would be of great benefit. However, in most systems currently deployed, the tool does not connect on-line with the AMI applications. Some tools do communicate with the Meter, but must be brought back to a central location to communicate with applications – typically only the Work Management System.



**Figure 7** – Potential Field Tool Connectivity

Some of the most basic questions of Field Tool interoperability have yet to be answered:

- **What applications must the Field Tool talk to?** The Work Management System is one obvious answer, but

it would also be useful to access the Customer Information System, Asset Management System, and perhaps directly communicate with the MDMS or the Metering System to see recent data or test the AMI connection to the meter. Some use cases have been defined, but the business processes of using the Field Tool in this way are mostly speculation.

- **What standards should it use to communicate?** IEC 61968 Part 9 leaves workforce management to Part 6, (which is similarly not finished yet) and otherwise does not discuss Field Tools. This area of communications standardization needs some attention by industry working groups.
- **Which path does the data follow?** One of the reasons that Field Tool use cases are so difficult to develop is that there is no consensus on the sequence of information flow, and what path it should follow. In the process of installing a meter, for instance, the Field Tool could read the physical location of the meter using a GPS sensor. Should the Field Tool pass that information to the Meter, assuming the Meter will forward it to the AMI applications when the Meter registers with the Metering System? Or should the Field Tool include the GPS information in the final copy of the Work Order when it is closed, and the WMS pass it to the Asset Management System? These questions have not been resolved.

**2.8. HAN Gateway Tunneling**

The discussion about connecting HAN devices to the Field WAN and the rest of the AMI has understandably focused on developing use cases and on establishing security mechanisms to ensure there are no unauthorized accesses to either the utility networks or to the customer premise equipment. These are undeniably the first priorities in making a utility gateway to the home possible.

However, customer service managers at some utilities have been dismayed to discover that the type of HAN access that is being defined is not what they expected. They were expecting a “tunneling” ability, but what has been developed by the standards groups is an application layer gateway.

As illustrated in Figure 8, some utilities have selected HAN devices that are supplied with a management software application. This application was intended to be used by the customer on the customer premise to monitor and configure the HAN device. Sometimes the interface to the device is proprietary, sometimes it may be a standard such as ZigBee, WiFi or 6LowPAN.

In any case, the application often has features that provide value added in managing or monitoring the device. Utilities would like to make use of this application remotely from the

Enterprise domain. Such an application would be known as “tunneling” the communications through the ESB, WAN, Field LAN and HAN. It would not be an unreasonable expectation if the networks involved were all IP-based. It is similar to the type of access to the AMI networks desired by those deploying distribution automation devices.

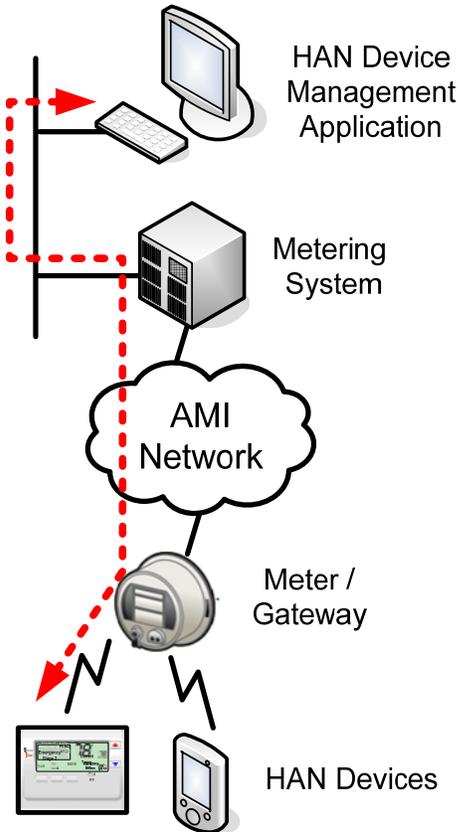


Figure 8 – Desired HAN Tunneling Access

Unfortunately, even systems that use open standards such as IEC 61968, ANSI C12.22, IP and ZigBee do not provide this tunneling ability. That is because there is typically an application layer gateway at the Metering System, and there is always one at the Meter or Premise Gateway.

For both security and ease of implementation, a Meter or Premise Gateway performs a mapping between the services and data models of the Field LAN and HAN technologies, such as ANSI C12.22 and ZigBee. Both communications stacks are essentially terminated within the gateway; no tunneling of message without modification, as desired and shown in Figure 8, can take place.

At least one vendor has attempted a simplified form of tunneling, in which ZigBee messages are stored in ANSI C12 meter event logs and brought back to the MDMS

through the Metering System. While better than nothing, this mechanism is awkward at best.

The only way tunneling could happen is if there were a common network layer between the Field LAN and HAN. The closest implementation to this situation using existing technologies would be a Field LAN using IPv6 and a HAN using 6LowPAN. While the mapping between these two technologies is not perfect, it is at least below the application layer and may permit tunneling. Few HANs now offered use IPv4.

### 3. CONCLUSIONS

Many readers of this paper may disagree with the assertion that the problems described here are interoperability problems. They would argue that many of the questions raised here are not related to interoperability, but are merely the type of questions that any systems integrator must ask. Particularly, questions of the form, “Where should this task be performed?” and “In what sequence should tasks be performed?” are often seen to be project-specific choices made by a utility or integrator.

However, according to the GridWise Architecture Council (GWAC) interoperability framework ([3] and summarized in Figure 9), this is not a valid argument.

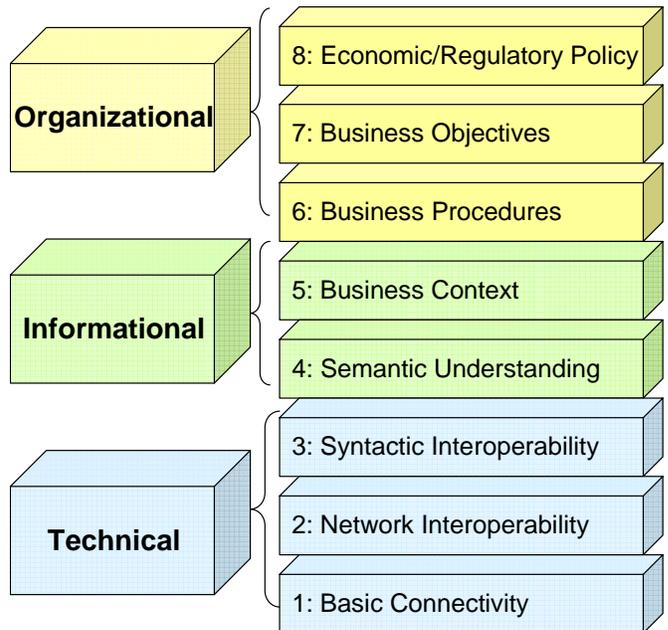


Figure 9 – GridWise Interoperability Framework

This framework shows that there are many more layers to interoperability than the traditional 7-Layer Open Systems Interconnect model. The OSI model is essentially represented by the three “Technical” layers in the GWAC framework. There are five more layers of interoperability above them. In essence, the framework states that is not sufficient

to standardize the bits and bytes of communication, but also the context and business processes surrounding that communication.

Table 7 shows why people are not used to thinking of issues like those identified in this paper as interoperability concerns. The reason is that most of them fall in the Informational or Organizational portions of the GWAC framework.

**Table 7 – Concerns in this Paper vs. the GWAC Framework**

Interoperability Concern	Key Framework Level
Where does topology information come from?	Business Procedures
How to keep the topology model up to date?	Basic Connectivity
What level of topology detail and accuracy to keep?	Syntactic Interoperability
Where is the topology information stored?	Business Procedures
Who uses the topology information?	Business Procedures
Where to filter events?	Semantic Understanding
What criteria to use for filtering?	Semantic Understanding
Which system makes outage management decisions?	Business Procedures, Business Context, Semantic Understanding
How to coordinate outage management, demand response and theft detection?	Business Procedures, Syntactic Interoperability
How to ensure the billing process is not delayed?	Business Procedures, Business Context, Semantic Understanding
How to ensure a common data interface?	Syntactic Interoperability
How often should data be updated?	Semantic Understanding
How many databases are needed?	Syntactic Interoperability
Proprietary field LANs	Network Interoperability
Distribution automation access	Network Interoperability
What applications must the Field Tool talk to?	Business Procedures
What standards should the Field Tool use to communicate?	Syntactic Interoperability, Network Interoperability, Basic Connectivity
Which path does the field tool data follow?	Business Procedures, Business Context, Network Interoperability
HAN Gateway Tunneling	Network Interoperability

Until these issues and others like them can be resolved and standardized, starting with an agreement on the names of the typical components of an AMI, it will be difficult to implement multi-vendor AMI solutions. Furthermore, the integration of AMI into the enterprise will continue to be a

labor-intensive process, and vendor lock-in will continue to be a concern.

In the meantime, the following measures will help to alleviate some of these problems:

- Participate in the IEC 61968-9 standardization process and ensure that not only message structure, but transmission syntax and business processes are captured in that standard.
- Participate in industry efforts to recommend guidelines for the use of ANSI C12.19 and C12.22.
- Capture topology information as a part of the AMI deployment process, and encourage suppliers to develop technology for automatic topology capture.
- Filter events at as high a level as possible permitted by the available bandwidth.
- Try to incorporate legacy systems into newer systems, or replace them outright, rather than successively creating incremental add-ons to the legacy systems.
- Provide multiple interfaces for retrieving different latencies and quality of data based on the application.
- Keep the MDMS and Meter Data Warehouse as up-to-date as possible given processing power and billing restrictions
- Record outage, restoration and demand response event information along with the usage data, as low down in the data chain as possible.
- Request as much bandwidth in your Field LAN as possible, even if it is not strictly required by your applications. It will help to improve interoperability in the future.
- Encourage suppliers to consider online connectivity of Field Tools and the tunneling of distribution automation or HAN management data on the AMI networks.

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**Biography**

Grant Gilchrist, P. Eng., is a Consulting Engineer and Systems Architect on the Smart Grid Engineering Team at EnerNex Corporation. He is a member of several utility data communications standards bodies including the IEC working groups for SCADA, substation automation, protocol security, and interoperability. He is a founding member of the Technical Committee for the Distributed Network Protocol (DNP3). He has facilitated the development of use cases and technical requirements for AMI at Southern California Edison, CMS Energy, and BC Hydro.

Before joining EnerNex, Grant spent a total of 17 years developing embedded data communications software for GE Energy and Nortel Networks. He has a Bachelor of Applied Science in Systems Engineering from the University of Regina, Saskatchewan, and is a registered Professional Engineer in the province of Alberta, Canada.

# Next-Generation Power Information System

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## Keywords:

Common Information Model (CIM), Energy Management Systems (EMS), SCADA, GIS, OMS, Power Quality, Power Monitoring

## Abstract

Power monitoring systems (power quality monitors, digital fault recorders, digital relays, advanced controllers, etc.) continue to get more powerful and provide a growing array of benefits to overall power system operation and performance evaluation. Permanent monitoring systems are used to track ongoing performance, to watch for conditions that could require attention, and to provide information for utility and customer personnel when there is a problem to investigate. An important development area for these monitoring systems is the implementation of intelligent systems that can automatically evaluate disturbances and conditions to make conclusions about the cause of a problem or even predict problems before they occur.

This paper describes the development of a Next Generation Power Information System that will provide an open platform for implementing advanced monitoring system applications that involve integration with many different data sources. The work builds on many years of experience with software for management and analysis of large power quality monitoring systems.

## BENEFITS

Interoperability and open access to data are cornerstones to successful development and implementation of advanced smart-grid applications at the enterprise level. An integrated platform is needed that includes access to power quality data and disturbance data in addition to traditional data stores such as historians, GIS, and electrical models. Key benefits that are realized when this integration occurs include:

- **Advanced applications that are based on disparate utility information systems.**

- **Automated data analysis using intelligent algorithms.**
- **Enterprise wide (web-based) data access, reporting, and alarming .**
- **Improved performance of transmission and distribution systems through advanced applications, such as fault location and equipment diagnostics.**

In operating and maintaining a power system, the timeliness and accuracy of available information has a direct impact on the efficiency and effectiveness of the system. It also has a direct impact on the safety of employees and the public. Seamlessly integrated and automated processes that take advantage of newer and smarter remote data gathering devices reduce the time that is required to understand system dynamics and return to the optimum state.

## BACKGROUND

Monitoring and recording power quality data can result in especially large databases. And, applications like PQView operate on these databases for data management, analysis, and reporting. Figure 1 is an example of a typical power quality monitoring system.

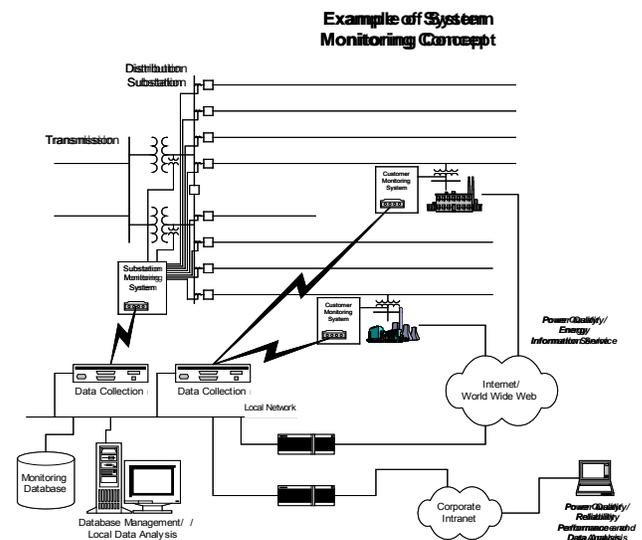


Figure 1. Configuration for PQ Monitoring Systems

As isolated projects have been implemented to integrate data from a wider variety of smart system devices including digital fault recorders, digital relays, power meters, and revenue meters, it has become increasingly evident that traditional tools are not enough. Functions similar to those found in PQView are needed by many people across the entire utility industry. The Next-Generation Power Information System is architected to support key principles of interoperability using methodologies such as service oriented architecture, well defined points of interoperability, and standards based interface design. Existing data silos limit the value of system infrastructure. Each data source has been created to address a specific system problem. And although these specific applications may be very efficient at performing their designed task, the data can be leveraged for much greater value when it is made available to a wider audience and combined with other system data.

There has been a growing demand for use of information managed in power quality databases in a wider variety of utility applications, like fault location and equipment diagnostics. These applications significantly expand the usefulness of the power quality information, but also impose new requirements on the data management system and access to the data.

To date, these new applications have required custom development and custom interfaces to other information system platforms within the utility for implementation. The Next Generation Power Information System platform will provide the means of integrating monitoring data with a wide variety of other power system information (GIS, electrical models, operations, assets, external conditions, lightning, etc.) to provide a platform for the development of many advanced applications.

#### ARCHITECTURE FOR THE NEXT-GENERATION POWER INFORMATION SYSTEM

The architecture will provide an open interface and will allow integration with the wide variety of systems that can provide valuable information for advanced applications – Energy Management Systems, Historians, Outage Management Systems, Geographical Information Systems, Electrical Models for Planning and Operations, etc. The interfaces can take advantage of an enterprise service bus or could involve open point-to-point interfaces. Figure 2 illustrates the concept.

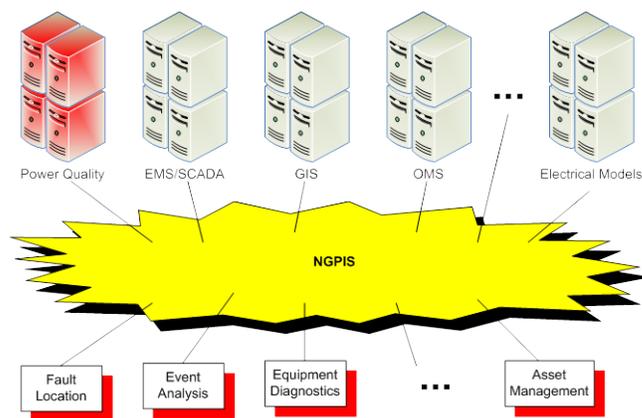


Figure 2. Conceptual architecture for the next generation power information system.

The Next-Generation Power Information System will enable applications to share power system information across the enterprise. International industry standards (IEC 61970/61968, PQDIF, COMTRADE, OpenGIS®, etc.) will be used whenever applicable to enhance the visibility and usefulness of the data. The user interface to the system will be web-enabled to allow sharing of data across the enterprise without requiring the support of workstation applications on computers throughout the company.

The system will facilitate the inclusion of data from any intelligent electronic device such as digital relays, digital fault recorders, and meters and other power system information sources like external databases and systems.

Where appropriate, the system will expose information via industry standard interfaces that will facilitate integration with other applications, including web-based applications.

#### DETAILED OBJECTIVES FOR PLATFORM

These objectives provide the foundation for the Next Generation Power Information System. With these objectives, the system will enable a wide variety of advanced applications that can be developed independently of the platform itself.

1. Provide an open platform for managing and providing access to power system information to facilitate a wide variety of applications that enhance the understanding and actual performance of the power system and power system equipment.

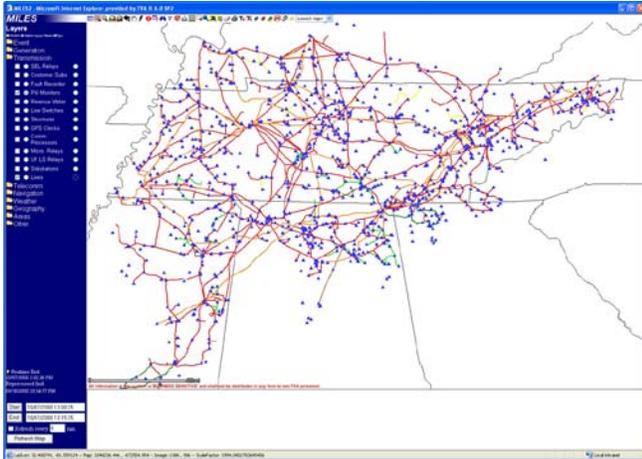


Figure 3. Example of web-based interface to monitoring system information integrated with GIS and transmission system electrical configuration

2. Scalable system that can provide the basis for information management encompassing the integration of data from a growing array of monitors, sensors, and meters.
  - Monitoring data from smart devices in virtually every substation on the power system
  - Monitoring data from monitors, sensors, controllers, etc. throughout the transmission and distribution systems (line and equipment monitors and sensors, device controllers such as regulators, reclosers, capacitor banks, etc)
  - Monitoring data from advanced revenue meters at potentially every single customer (only selected customers would have advanced monitoring functionality but the system should support this)
3. Web-based interfaces for managing the entire infrastructure.
4. Open, standards-based interfaces for accessing the information so that third parties can develop applications that use the information in the system along with information from many other systems to improve the performance of the power system and power system equipment.
5. Illustrate the implementation of new applications with a core group of power quality applications:
  - Web-based management of the power information system data collection and data management

- Web-based access to system information with convenient user interfaces, such as:
  - trending of virtually any parameter (single location or multiple location)
  - viewing and analysis of disturbances (waveforms, rms, event characteristics)
  - GIS views to select data and view data
  - correlation of data with other information systems (lightning, operations, electrical models)
- Flexible reporting of power quality performance
  - Site reports that are GIS-based, user-defined information, automated, combined with automated notification based on user-defined criteria
  - System performance reports that combine information from sites across the system that are GIS-based, include important system characteristics, operations data, electrical model information, and other external conditions such as lightning and weather.
  - Ability to incorporate key aspects of both site reports and system reports into dashboard summaries for web-based presentation and access.
- Example system analysis functions such as Fault Location (see Figure 4)
  - Web-based configuration of parameters for analysis of fault events
  - Documented interface requirements for other systems needed – electrical models, operations data, GIS, lightning, OMS
  - Web-based configuration of reports and notifications
- Example equipment diagnostics application such as capacitor bank performance assessment (See Figure 5)

- Web-based configuration of parameters for assessment of capacitor bank performance (voltage and current profiles, disturbance characteristics such as restrike transients, unbalance, harmonics)
- Documented interface requirements for other systems needed - capacitor bank data, electrical models, GIS, operations data
- Web-based configuration of reports and notifications

6. Foundation for ongoing development of a wide variety of advanced reports and applications

- Reports and analysis functions to benefit both utility engineers and customers
- Automatic identification of lightning-caused events and location of these events
- Automatic identification of locations with harmonic resonance problems
- Identification of equipment problems (voltage regulators, transformers, breakers, etc.)
- Input to asset management and equipment health assessment applications

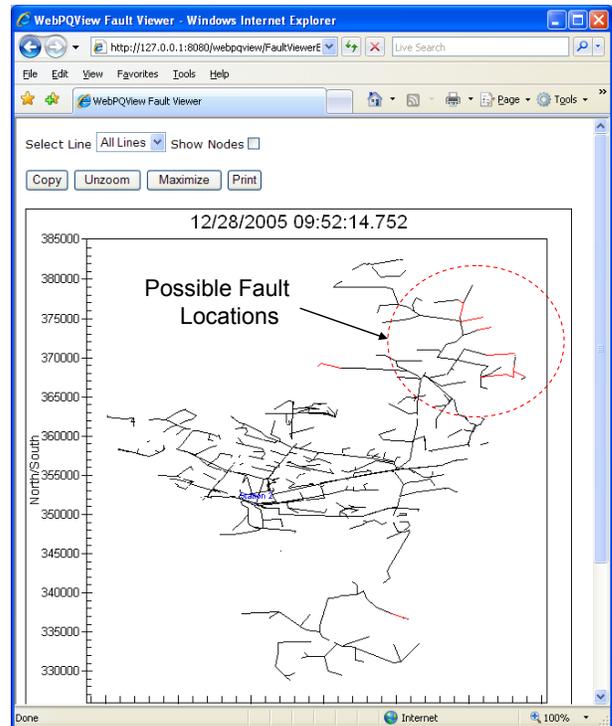
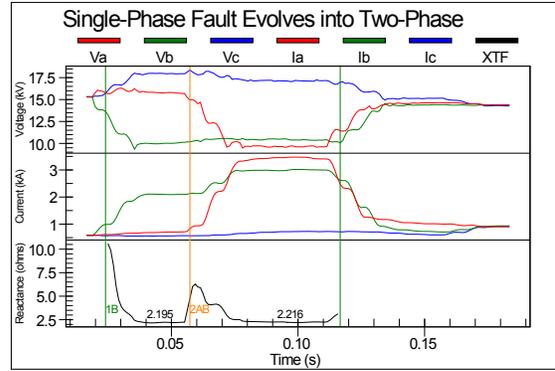


Figure 4. Example of fault location application using substation waveform data along with GIS and electrical model information to locate faults

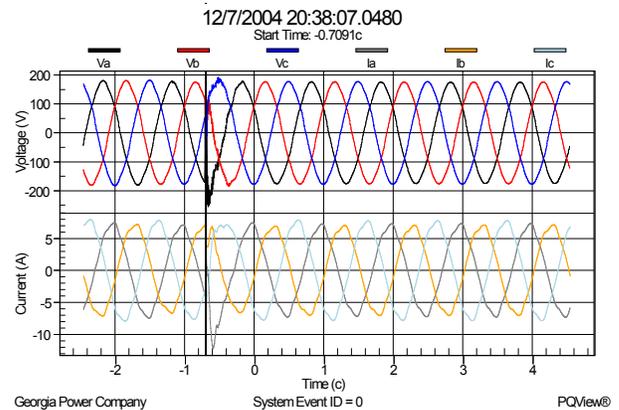
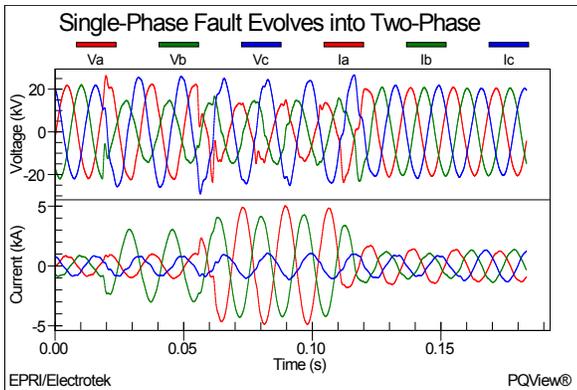




Figure 5. Example of transient waveform (capacitor restriking) that can be identified automatically to indicate a breaker problem.

### DEVELOPING THE PLATFORM

The Next Generation Power Information System is being specified and a conceptual design is being completed by the Electric Power Research Institute (EPRI) in cooperation with a core group of initial sponsors – Tennessee Valley Authority, Con Edison, Southern Company, Salt River Project, and City Public Service of San Antonio.

The new platform will open power quality systems to a much greater variety of applications that use the power quality information in combination with data from a wide variety of other sources. This will be accomplished by implementing a modular software system with modules built in multiple tiers (see Figure 6).

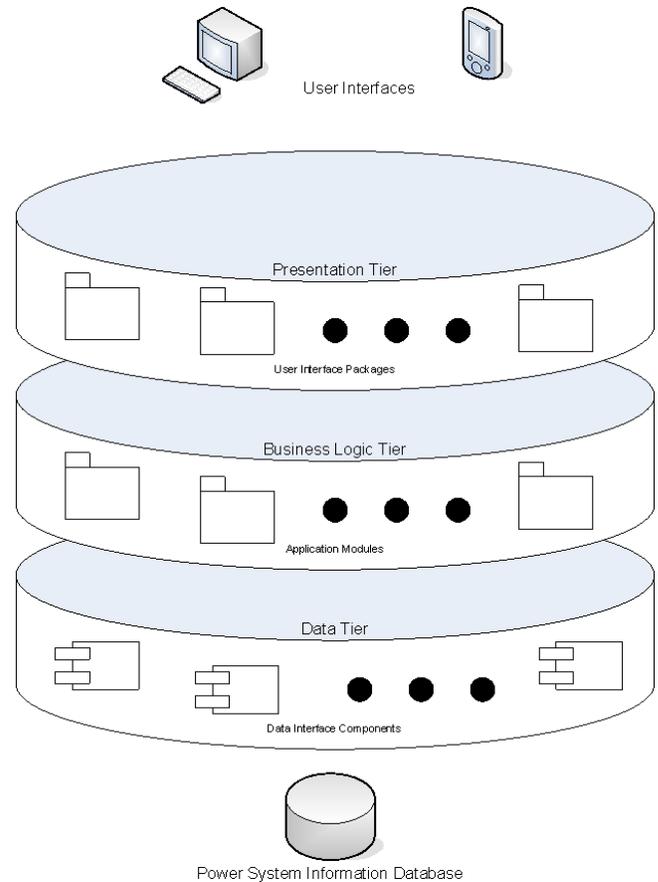


Figure 6. Concept of modular implementation of the next generation platform in multiple tiers to facilitate open development of advanced applications.

### SUMMARY

A new information management system is described that will provide web-based access and management to a wide variety of power system information. It is built around integration of monitoring information with other enterprise information systems. The new architecture will facilitate a variety of important aspects of the smart grid:

- The system will provide web-based interfaces for all key functions. This greatly reduces the software support requirements within utilities and dramatically increases the value of the system by making access to information, reports, and analysis results available to a much wider range of users, both internal and external to the company.
- The system will facilitate application level interfaces to other key information systems, especially GIS, electrical models, operations, and equipment databases.

- The reporting functions of the system will be structured with web-based interfaces for flexible configuration of reporting at both the site and system level so that users can define their specific reporting and notification needs.
- The system will be scalable to support the wide variety and dramatically expanding range of information resources becoming available to characterize the power system and equipment performance. Instead of supporting monitoring data from hundreds of power quality monitors, the system must be able to support information from throughout virtually every substation, transmission system, distribution system, and even every single customer on the power system. The number of points to support is quickly growing to the tens of thousands and will be migrating to the millions.
- The system will provide an open, documented interface for third parties to access the information, facilitating the development of advanced applications by a wide range of internal and external developers. These application interfaces to the system can be thought of as a “developer’s toolkit”.

## BIOGRAPHIES

**Fred L. Elmendorf** is the Power Quality Manager for Power System Operations of the Tennessee Valley Authority (TVA), in Chattanooga, Tennessee. He is responsible for all long term PQ monitoring projects within TVA, and the integration of other data sources including digital fault recorders, solid state relays, and revenue meters, into the Power Quality system. He is also responsible for managing TVA’s lightning data systems including the National Lightning Detection Network (NLDN), the Fault Analysis and Lightning Location System (FALLS), and the integration of PQ and lightning data.

Fred has been with TVA for over 28 years, and has been increasingly involved with PQ since 1992, and lightning data since 1995. In addition to PQ and lightning, he has developed and supported applications in many engineering research areas including active and passive solar thermal storage, renewable energy sources, and conservation and energy management. Fred received a B.S. degree in Computer Science from the University of Tennessee at Chattanooga.

**Mark McGranaghan** is a Director in the EPRI Power Delivery and Utilization (PDU) Sector. His research area

responsibilities include overhead and underground distribution, advanced distribution automation, Intelligrid, and power quality. Research priorities include developing the technologies, application guidelines, interoperability approaches, and standards for implementing the smart grid infrastructure that will be the basis of automation, higher efficiency, improved reliability, and integration of distributed resources and demand response. He is also directing EPRI’s extensive smart grid demonstration initiative (5 year effort) to help coordinate the industry approach for distributed resource integration with the operation of the grid.

**Zhiming Dai** is a Software Development Manager at EPRI. His current research activity focus on developing next generation power information system, he has been in charge of developing various high tech business and application development executive with background in telecommunication industries and electric industries. Zhiming Dai received his Computer Science B.S degree from Shanghai Industry University, Computer Science M.S. degree from Oklahoma State University and EMBA from MIT.

**Christopher J. Melhorn** is a Program Manager in the Power Quality program area of EPRI’s Power Delivery and Markets Sector. His current research activities focus on developing intelligent applications of monitoring systems for member utilities, managing EPRI’s MyPQ.net Web site, and performing power systems research for the private sector. His previous activities included management of the EPRI Distribution Power Quality (DPQ) II study.

Before joining EPRI in 2000, Mr. Melhorn worked at Electrotek Concepts, Inc. In his role there as Manager of Power Quality Products and Services, he was responsible for developing new products and services related to state-of-the-art monitoring systems for Utilities and Large Industrial & Commercial end-users.

Mr. Melhorn received a B.S. in Electrical Engineering Technology from the Pennsylvania State University and an A.S. Degree from York College of Pennsylvania. He has authored over 35 technical papers, was a contributing author on three technical books related to power systems and power quality, and has developed and taught numerous seminars and workshops related power systems and power quality.